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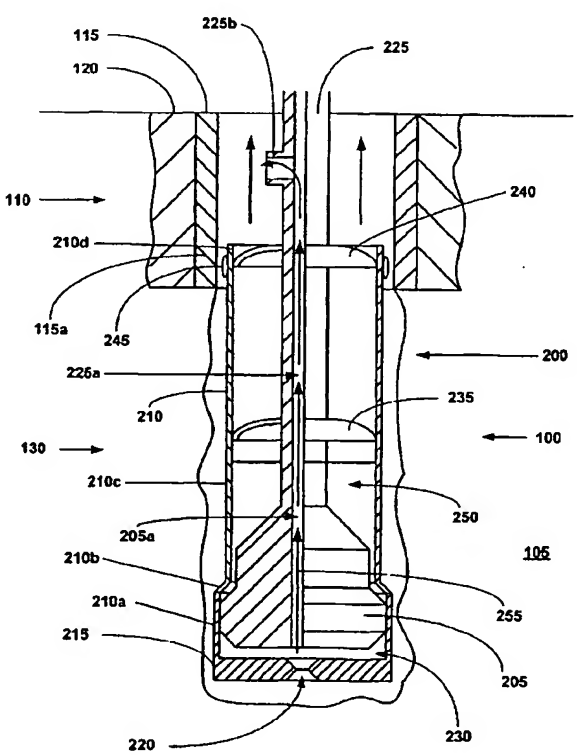
(54) Title: MONO-DIAMETER WELLBORE CASING



(57) Abstract: A mono-diameter casing formed when a tubular liner (210) and an expansion cone (205) are positioned within a new section fo a wellbore (100) and the tubular liner (210) is overlapped with a pre-existing casing (115). A hardening fluid is injected into the section of the wellbore (100) below the level of the expansion cone (205) and into the annular region between the tubular liner (210) and the wellbore (100). The inner and outer regions of the tubular liner (210) are isolated. Then a non-hardening fluid is injected into the interior region of the tubular liner (210) to pressurize it below the expansion cone (205). The overlapping portion of the pre-existing casing (115) and the tubular liner (210) are then expanded using an expansion cone (205).

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MONO-DIAMETER WELLBORE CASING

Background of the Invention

This invention relates generally to wellbore casings, and in particular to wellbore casings that are formed using expandable tubing, as well as to the joining of tubular members in subterranean formations.

Conventionally, when a wellbore is created, a number of casings are installed in the borehole to prevent collapse of the borehole wall and to prevent undesired outflow of drilling fluid into the formation or inflow of fluid from the formation into the borehole. The borehole is drilled in intervals whereby a casing which is to be installed in a lower borehole interval is lowered through a previously installed casing of an upper borehole interval. As a consequence of this procedure the casing of the lower interval is of smaller diameter than the casing of the upper interval. Thus, the casings are in a nested arrangement with casing diameters decreasing in downward direction. Cement annuli are provided between the outer surfaces of the casings and the borehole wall to seal the casings from the borehole wall. As a consequence of this nested arrangement a relatively large borehole diameter is required at the upper part of the wellbore. Such a large borehole diameter involves increased costs due to heavy casing handling equipment, large drill bits and increased volumes of drilling fluid and drill cuttings. Moreover, increased drilling rig time is involved due to required cement pumping, cement hardening, required equipment changes due to large variations in hole diameters drilled in the course of the well, and the large volume of cuttings drilled and removed.

The present invention is directed to overcoming one or more of the limitations of the existing procedures for forming new sections of casing in a wellbore.

Summary of the Invention

According to one aspect of the present invention, a method of creating a mono-diameter wellbore casing in a borehole located in a subterranean formation including a preexisting wellbore casing is provided that includes installing a tubular liner and a first expansion cone in the borehole, injecting a fluidic material into the borehole, pressurizing a portion of an interior region of the tubular liner below the first expansion cone, radially expanding at least a portion of the tubular liner in the borehole by extruding at least a

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portion of the tubular liner off the first expansion cone, and radially expanding at least a portion of the preexisting wellbore casing and the tubular liner using a second expansion cone.

According to another aspect of the present invention, apparatus for forming a mono-diameter wellbore casing in a borehole located in a subterranean formation including a preexisting wellbore casing is provided that includes means for installing a tubular liner and a first expansion cone in the borehole, means for injecting a fluidic material into the borehole, means for pressurizing a portion of an interior region of the tubular liner below the first expansion cone, means for radially expanding at least a portion of the tubular liner in the borehole by extruding at least a portion of the tubular liner off the first expansion cone, and means for radially expanding at least a portion of the preexisting wellbore casing and the tubular liner using a second expansion cone.

According to another aspect of the present invention, a method of joining a second tubular member to a first tubular member positioned within a subterranean formation, the first tubular member having an inner diameter greater than an outer diameter of the second tubular member is provided that includes positioning a first expansion cone within an interior region of the second tubular member, pressurizing a portion of the interior region of the second tubular member adjacent to the first expansion cone, extruding at least a portion of the second tubular member off the first expansion cone into engagement with the first tubular member, and radially expanding at least a portion of the first tubular member and the second tubular member using a second expansion cone.

According to another aspect of the present invention, apparatus for joining a second tubular member to a first tubular member positioned within a subterranean formation, the first tubular member having an inner diameter greater than an outer diameter of the second tubular member, is provided that includes means for positioning a first expansion cone within an interior region of the second tubular member, means for pressurizing a portion of the interior region of the second tubular member adjacent to the first expansion cone, means for extruding at least a portion of the second tubular member off the first expansion cone into engagement with the first tubular member, and means for radially expanding at least a portion of the first tubular member and the second tubular member using a second expansion cone.

According to another aspect of the present invention, apparatus is provided that includes a wellbore casing coupled to a borehole in a subterranean formation, and a tubular liner coupled to the wellbore casing. The inside diameters of the wellbore casing and the tubular liner are substantially equal, and the tubular liner is coupled to the wellbore casing by a method that includes installing the tubular liner and a first expansion cone in the borehole, injecting a fluidic material into the borehole, pressurizing a portion of an interior region of the tubular liner below the first expansion cone, radially expanding at least a portion of the tubular liner in the borehole by extruding at least a portion of the tubular liner off the first expansion cone, and radially expanding at least a portion of the wellbore casing and the tubular liner using a second expansion cone.

According to another aspect of the present invention, apparatus is provided that includes a first tubular member coupled to a borehole in a subterranean formation, and a second tubular member coupled to the first tubular member. The inside diameters of the first and second tubular members are substantially equal, and the second tubular member is coupled to the first tubular member by a method that includes installing the second tubular member and a first expansion cone in the borehole, injecting a fluidic material into the borehole, pressurizing a portion of an interior region of the second tubular member below the first expansion cone, radially expanding at least a portion of the second tubular member in the borehole by extruding at least a portion of the second tubular member off of the first expansion cone, and radially expanding at least a portion of the first tubular member and the second tubular member using a second expansion cone.

Brief Description of the Drawings

Various embodiments of methods and apparatus in accordance with the invention will now be described by way of example only, with reference to the accompanying drawings, in which:

FIG. 1 is a fragmentary cross-sectional view illustrating the drilling of a new section of a well borehole.

FIG. 2 is a fragmentary cross-sectional view illustrating the placement of an embodiment of an apparatus for creating a casing within the new section of the well borehole of FIG. 1.

FIG. 3 is a fragmentary cross-sectional view illustrating the injection of a hardenable

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fluidic sealing material into the new section of the well borehole of FIG. 2.

FIG. 4 is a fragmentary cross-sectional view illustrating the injection of a fluidic material into the new section of the well borehole of FIG. 3.

FIG. 5 is a fragmentary cross-sectional view illustrating the drilling out of the cured hardenable fluidic sealing material and the shoe from the new section of the well borehole of FIG. 4.

FIG. 6 is a cross-sectional view of the well borehole of FIG. 5 following the drilling out of the shoe.

FIG. 7 is a fragmentary cross-sectional view of the placement and actuation of an expansion cone within the well borehole of FIG. 6 for forming a mono-diameter wellbore casing.

FIG. 8 is a cross-sectional illustration of the well borehole of FIG. 7 following the formation of a mono-diameter wellbore casing.

FIG. 9 is a cross-sectional illustration of the well borehole of FIG. 8 following the repeated operation of the methods of FIGS. 1-8 in order to form a mono-diameter wellbore casing including a plurality of overlapping wellbore casings.

FIG. 10 is a fragmentary cross-sectional illustration of the placement of an alternative embodiment of an apparatus for forming a mono-diameter wellbore casing into the well borehole of FIG. 6.

FIG. 11 is a cross-sectional illustration of the well borehole of FIG. 10 following the formation of a mono-diameter wellbore casing.

FIG. 12 is a fragmentary cross-sectional illustration of the placement of an alternative embodiment of an apparatus for forming a mono-diameter wellbore casing into the well borehole of FIG. 6.

FIG. 13 is a fragmentary cross-sectional illustration of the well borehole of FIG. 12 during the injection of pressurized fluids into the well borehole.

FIG. 14 is a fragmentary cross-sectional illustration of the well borehole of FIG. 13 during the formation of the mono-diameter wellbore casing.

FIG. 15 is a fragmentary cross-sectional illustration of the well borehole of FIG. 14 following the formation of the mono-diameter wellbore casing.

Detailed Description of the Illustrative Embodiments

Referring initially to FIGS. 1-9, an embodiment of an apparatus and method for forming a mono-diameter wellbore casing within a subterranean formation will now be described. As illustrated in Fig. 1, a wellbore 100 is positioned in a subterranean formation 105. The wellbore 100 includes a pre-existing cased section 110 having a tubular casing 115 and an annular outer layer 120 of a fluidic sealing material such as, for example, cement. The wellbore 100 may be positioned in any orientation from vertical to horizontal. In several alternative embodiments, the pre-existing cased section 110 does not include the annular outer layer 120.

In order to extend the wellbore 100 into the subterranean formation 105, a drill string 125 is used in a well known manner to drill out material from the subterranean formation 105 to form a new wellbore section 130.

As illustrated in FIG. 2, an apparatus 200 for forming a wellbore casing in a subterranean formation is then positioned in the new section 130 of the wellbore 100. The apparatus 200 preferably includes an expansion cone 205 having a fluid passage 205a that supports a tubular member 210 that includes a lower portion 210a, an intermediate portion 210b, an upper portion 210c, and an upper end portion 210d.

The expansion cone 205 may be any number of conventional commercially available expansion cones. In several alternative embodiments, the expansion cone 205 may be controllably expandable in the radial direction, for example, as disclosed in U.S. patent nos. 5,348,095, and/or 6,012,523, the disclosures of which are incorporated herein by reference.

The tubular member 210 may be fabricated from any number of conventional commercially available materials such as, for example, Oilfield Country Tubular Goods (OCTG), 13 chromium steel tubing/casing, or plastic tubing/casing. In a preferred embodiment, the tubular member 210 is fabricated from OCTG in order to maximize strength after expansion. In several alternative embodiments, the tubular member 210 may be solid and/or slotted. In a preferred embodiment, the length of the tubular member 210 is limited to minimize the possibility of buckling. For typical tubular member 210 materials, the length of the tubular member 210 is preferably limited to between about 40 to 20,000 feet in length.

The lower portion 210a of the tubular member 210 preferably has a larger inside diameter than the upper portion 210c of the tubular member. In a preferred embodiment, the wall thickness of the intermediate portion 210b of the tubular member 201 is less than the wall thickness of the upper portion 210c of the tubular member in order to facilitate the initiation of the radial expansion process. In a preferred embodiment, the upper end portion 210d of the tubular member 210 is slotted, perforated, or otherwise modified to catch or slow down the expansion cone 205 when it completes the extrusion of tubular member 210.

A shoe 215 is coupled to the lower portion 210a of the tubular member. The shoe 215 includes a valveable fluid passage 220 that is preferably adapted to receive a plug, dart, or other similar element for controllably sealing the fluid passage 220. In this manner, the fluid passage 220 may be optimally sealed off by introducing a plug, dart and/or ball sealing elements into the fluid passage 240.

The shoe 215 may be any number of conventional commercially available shoes such as, for example, Super Seal II float shoe, Super Seal II Down-Jet float shoe or a guide shoe with a sealing sleeve for a latch down plug modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the shoe 215 is an aluminum down-jet guide shoe with a sealing sleeve for a latch-down plug available from Halliburton Energy Services in Dallas, TX, modified in accordance with the teachings of the present disclosure, in order to optimally guide the tubular member 210 in the wellbore, optimally provide an adequate seal between the interior and exterior diameters of the overlapping joint between the tubular members, and to optimally allow the complete drill out of the shoe and plug after the completion of the cementing and expansion operations.

In a preferred embodiment, the shoe 215 further includes one or more through and side outlet ports in fluidic communication with the fluid passage 220. In this manner, the shoe 215 optimally injects hardenable fluidic sealing material into the region outside the shoe 215 and tubular member 210.

A support member 225 having fluid passages 225a and 225b is coupled to the expansion cone 205 for supporting the apparatus 200. The fluid passage 225a is preferably fluidicly coupled to the fluid passage 205a. In this manner, fluidic materials may be conveyed to and from a region 230 below the expansion cone 205 and above the bottom of the shoe 215. The fluid passage 225b is preferably fluidicly coupled to the fluid passage

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225a and includes a conventional control valve. In this manner, during placement of the apparatus 200 within the wellbore 100, surge pressures can be relieved by the fluid passage 225b. In a preferred embodiment, the support member 225 further includes one or more conventional centralizers (not illustrated) to help stabilize the apparatus 200.

During placement of the apparatus 200 within the wellbore 100, the fluid passage 225a is preferably selected to transport materials such as, for example, drilling mud or formation fluids at flow rates and pressures ranging from about 0 to 3,000 gallons/minute and 0 to 9,000 psi in order to minimize drag on the tubular member being run and to minimize surge pressures exerted on the wellbore 130 which could cause a loss of wellbore fluids and lead to hole collapse. During placement of the apparatus 200 within the wellbore 100, the fluid passage 225b is preferably selected to convey fluidic materials at flow rates and pressures ranging from about 0 to 3,000 gallons/minute and 0 to 9,000 psi in order to reduce the drag on the apparatus 200 during insertion into the new section 130 of the wellbore 100 and to minimize surge pressures on the new wellbore section 130.

A lower cup seal 235 is coupled to and supported by the support member 225. The lower cup seal 235 prevents foreign materials from entering the interior region of the tubular member 210 adjacent to the expansion cone 205. The lower cup seal 235 may be any number of conventional commercially available cup seals such as, for example, TP cups, or Selective Injection Packer (SIP) cups modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the lower cup seal 235 is a SIP cup seal, available from Halliburton Energy Services in Dallas, TX in order to optimally block foreign material and contain a body of lubricant.

The upper cup seal 240 is coupled to and supported by the support member 225. The upper cup seal 240 prevents foreign materials from entering the interior region of the tubular member 210. The upper cup seal 240 may be any number of conventional commercially available cup seals such as, for example, TP cups or SIP cups modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the upper cup seal 240 is a SIP cup, available from Halliburton Energy Services in Dallas, TX in order to optimally block the entry of foreign materials and contain a body of lubricant.

One or more sealing members 245 are coupled to and supported by the exterior surface of the upper end portion 210d of the tubular member 210. The seal members 245

preferably provide an overlapping joint between the lower end portion 115a of the casing 115 and the portion 260 of the tubular member 210 to be fluidicly sealed. The sealing members 245 may be any number of conventional commercially available seals such as, for example, lead, rubber, Teflon, or epoxy seals modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the sealing members 245 are molded from Stratalock epoxy available from Halliburton Energy Services in Dallas, TX in order to optimally provide a load bearing interference fit between the upper end portion 210d of the tubular member 210 and the lower end portion 115a of the existing casing 115.

In a preferred embodiment, the sealing members 245 are selected to optimally provide a sufficient frictional force to support the expanded tubular member 210 from the existing casing 115. In a preferred embodiment, the frictional force optimally provided by the sealing members 245 ranges from about 1,000 to 1,000,000 lbf in order to optimally support the expanded tubular member 210.

In a preferred embodiment, a quantity of lubricant 250 is provided in the annular region above the expansion cone 205 within the interior of the tubular member 210. In this manner, the extrusion of the tubular member 210 off of the expansion cone 205 is facilitated. The lubricant 250 may be any number of conventional commercially available lubricants such as, for example, Lubriplate, chlorine based lubricants, oil based lubricants or Climax 1500 Antisieze (3100). In a preferred embodiment, the lubricant 250 is Climax 1500 Antisieze (3100) available from Climax Lubricants and Equipment Co. in Houston, TX in order to optimally provide optimum lubrication to facilitate the expansion process.

In a preferred embodiment, the support member 225 is thoroughly cleaned prior to assembly to the remaining portions of the apparatus 200. In this manner, the introduction of foreign material into the apparatus 200 is minimized. This minimizes the possibility of foreign material clogging the various flow passages and valves of the apparatus 200.

In a preferred embodiment, before or after positioning the apparatus 200 within the new section 130 of the wellbore 100, a couple of wellbore volumes are circulated in order to ensure that no foreign materials are located within the wellbore 100 that might clog up the various flow passages and valves of the apparatus 200 and to ensure that no foreign material interferes with the expansion process.

As illustrated in FIG. 2, in a preferred embodiment, during placement of the

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apparatus 200 within the wellbore 100, fluidic materials 255 within the wellbore that are displaced by the apparatus are conveyed through the fluid passages 220, 205a, 225a, and 225b. In this manner, surge pressures created by the placement of the apparatus within the wellbore 100 are reduced.

As illustrated in FIG. 3, the fluid passage 225b is then closed and a hardenable fluidic sealing material 305 is then pumped from a surface location into the fluid passages 225a and 205a. The material 305 then passes from the fluid passage 205a into the interior region 230 of the tubular member 210 below the expansion cone 205. The material 305 then passes from the interior region 230 into the fluid passage 220. The material 305 then exits the apparatus 200 and fills an annular region 310 between the exterior of the tubular member 210 and the interior wall of the new section 130 of the wellbore 100. Continued pumping of the material 305 causes the material 305 to fill up at least a portion of the annular region 310.

The material 305 is preferably pumped into the annular region 310 at pressures and flow rates ranging, for example, from about 0 to 5000 psi and 0 to 1,500 gallons/min, respectively. The optimum flow rate and operating pressures vary as a function of the casing and wellbore sizes, wellbore section length, available pumping equipment, and fluid properties of the fluidic material being pumped. The optimum flow rate and operating pressure are preferably determined using conventional empirical methods.

The hardenable fluidic sealing material 305 may be any number of conventional commercially available hardenable fluidic sealing materials such as, for example, slag mix, cement or epoxy. In a preferred embodiment, the hardenable fluidic sealing material 305 is a blended cement prepared specifically for the particular well section being drilled from Halliburton Energy Services in Dallas, TX in order to provide optimal support for tubular member 210 while also maintaining optimum flow characteristics so as to minimize difficulties during the displacement of cement in the annular region 315. The optimum blend of the blended cement is preferably determined using conventional empirical methods. In several alternative embodiments, the hardenable fluidic sealing material 305 is compressible before, during, or after curing.

The annular region 310 preferably is filled with the material 305 in sufficient quantities to ensure that, upon radial expansion of the tubular member 210, the annular

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region 310 of the new section 130 of the wellbore 100 will be filled with the material 305.

In an alternative embodiment, the injection of the material 305 into the annular region 310 is omitted.

As illustrated in FIG. 4, once the annular region 310 has been adequately filled with the material 305, a plug 405, or other similar device, is introduced into the fluid passage 220, thereby fluidicly isolating the interior region 230 from the annular region 310. In a preferred embodiment, a non-hardenable fluidic material 315 is then pumped into the interior region 230 causing the interior region to pressurize. In this manner, the interior region 230 of the expanded tubular member 210 will not contain significant amounts of cured material 305. This also reduces and simplifies the cost of the entire process. Alternatively, the material 305 may be used during this phase of the process.

Once the interior region 230 becomes sufficiently pressurized, the tubular member 210 is preferably plastically deformed, radially expanded, and extruded off of the expansion cone 205. During the extrusion process, the expansion cone 205 may be raised out of the expanded portion of the tubular member 210. In a preferred embodiment, during the extrusion process, the expansion cone 205 is raised at approximately the same rate as the tubular member 210 is expanded in order to keep the tubular member 210 stationary relative to the new wellbore section 130. In an alternative preferred embodiment, the extrusion process is commenced with the tubular member 210 positioned above the bottom of the new wellbore section 130, keeping the expansion cone 205 stationary, and allowing the tubular member 210 to extrude off of the expansion cone 205 and into the new wellbore section 130 under the force of gravity and the operating pressure of the interior region 230.

The plug 405 is preferably placed into the fluid passage 220 by introducing the plug 405 into the fluid passage 225a at a surface location in a conventional manner. The plug 405 preferably acts to fluidicly isolate the hardenable fluidic sealing material 305 from the non hardenable fluidic material 315.

The plug 405 may be any number of conventional commercially available devices from plugging a fluid passage such as, for example, Multiple Stage Cementer (MSC) latch-down plug, Omega latch-down plug or three-wiper latch-down plug modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the plug 405 is a MSC latch-down plug available from Halliburton Energy Services in Dallas, TX.

After placement of the plug 405 in the fluid passage 220, the non hardenable fluidic material 315 is preferably pumped into the interior region 310 at pressures and flow rates ranging, for example, from approximately 400 to 10,000 psi and 30 to 4,000 gallons/min. In this manner, the amount of hardenable fluidic sealing material within the interior 230 of the tubular member 210 is minimized. In a preferred embodiment, after placement of the plug 405 in the fluid passage 220, the non hardenable material 315 is preferably pumped into the interior region 230 at pressures and flow rates ranging from approximately 500 to 9,000 psi and 40 to 3,000 gallons/min in order to maximize the extrusion speed.

In a preferred embodiment, the apparatus 200 is adapted to minimize tensile, burst, and friction effects upon the tubular member 210 during the expansion process. These effects will be depend upon the geometry of the expansion cone 205, the material composition of the tubular member 210 and expansion cone 205, the inner diameter of the tubular member 210, the wall thickness of the tubular member 210, the type of lubricant, and the yield strength of the tubular member 210. In general, the thicker the wall thickness, the smaller the inner diameter, and the greater the yield strength of the tubular member 210, then the greater the operating pressures required to extrude the tubular member 210 off of the expansion cone 205.

For typical tubular members 210, the extrusion of the tubular member 210 off of the expansion cone 205 will begin when the pressure of the interior region 230 reaches, for example, approximately 500 to 9,000 psi.

During the extrusion process, the expansion cone 205 may be raised out of the expanded portion of the tubular member 210 at rates ranging, for example, from about 0 to 5 ft/sec. In a preferred embodiment, during the extrusion process, the expansion cone 205 is raised out of the expanded portion of the tubular member 210 at rates ranging from about 0 to 2 ft/sec in order to minimize the time required for the expansion process while also permitting easy control of the expansion process.

When the upper end portion 210d of the tubular member 210 is extruded off of the expansion cone 205, the outer surface of the upper end portion 210d of the tubular member 210 will preferably contact the interior surface of the lower end portion 115a of the casing 115 to form an fluid tight overlapping joint. The contact pressure of the overlapping joint may range, for example, from approximately 50 to 20,000 psi. In a preferred embodiment,

the contact pressure of the overlapping joint ranges from approximately 400 to 10,000 psi in order to provide optimum pressure to activate the annular sealing members 245 and optimally provide resistance to axial motion to accommodate typical tensile and compressive loads.

The overlapping joint between the existing casing 115 and the radially expanded tubular member 210 preferably provides a gaseous and fluidic seal. In a particularly preferred embodiment, the sealing members 245 optimally provide a fluidic and gaseous seal in the overlapping joint. In an alternative embodiment, the sealing members 245 are omitted.

In a preferred embodiment, the operating pressure and flow rate of the non-hardenable fluidic material 315 is controllably ramped down when the expansion cone 205 reaches the upper end portion 210d of the tubular member 210. In this manner, the sudden release of pressure caused by the complete extrusion of the tubular member 210 off of the expansion cone 205 can be minimized. In a preferred embodiment, the operating pressure is reduced in a substantially linear fashion from 100% to about 10% during the end of the extrusion process beginning when the expansion cone 205 is within about 5 feet from completion of the extrusion process.

Alternatively, or in combination, a shock absorber is provided in the support member 225 in order to absorb the shock caused by the sudden release of pressure. The shock absorber may, for example, be any conventional commercially available shock absorber adapted for use in wellbore operations.

Alternatively, or in combination, an expansion cone catching structure is provided in the upper end portion 210d of the tubular member 210 in order to catch or at least decelerate the expansion cone 205.

Once the extrusion process is completed, the expansion cone 205 is removed from the wellbore 100. In a preferred embodiment, either before or after the removal of the expansion cone 205, the integrity of the fluidic seal of the overlapping joint between the upper end portion 210d of the tubular member 210 and the lower end portion 115a of the preexisting wellbore casing 115 is tested using conventional methods.

In a preferred embodiment, if the fluidic seal of the overlapping joint between the upper end portion 210d of the tubular member 210 and the lower end portion 115a of the

casing 115 is satisfactory, then any uncured portion of the material 305 within the expanded tubular member 210 is then removed in a conventional manner such as, for example, circulating the uncured material out of the interior of the expanded tubular member 210. The expansion cone 205 is then pulled out of the wellbore section 130 and a drill bit or mill is used in combination with a conventional drilling assembly 505 to drill out any hardened material 305 within the tubular member 210. In a preferred embodiment, the material 305 within the annular region 310 is then allowed to fully cure.

As illustrated in Fig. 5, preferably any remaining cured material 305 within the interior of the expanded tubular member 210 is then removed in a conventional manner using a conventional drill string 505. The resulting new section of casing 510 preferably includes the expanded tubular member 210 and an outer annular layer 515 of the cured material 305.

As illustrated in FIG. 6, the bottom portion of the apparatus 200 including the shoe 215 and dart 405 may then be removed by drilling out the shoe 215 and dart 405 using conventional drilling methods.

As illustrated in FIG. 7, an apparatus 600 for forming a mono-diameter wellbore casing is then positioned within the wellbore casing 115 proximate the tubular member 210 that includes an expansion cone 605 and a support member 610. In a preferred embodiment, the outside diameter of the expansion cone 605 is substantially equal to the inside diameter of the wellbore casing 115. The apparatus 600 preferably further includes a fluid passage 615 for conveying fluidic materials 620 out of the wellbore 100 that are displaced by the placement and operation of the expansion cone 605.

The expansion cone 605 is then driven downward using the support member 610 in order to radially expand and plastically deform the tubular member 210 and the overlapping portion of the tubular member 115. In this manner, as illustrated in FIG. 8, a mono-diameter wellbore casing is formed that includes the overlapping wellbore casings 115 and 210. In several alternative embodiments, the secondary radial expansion process is performed before, during, or after the material 515 fully cures. In several alternative embodiments, a conventional expansion device including rollers may be substituted for, or used in combination with, the apparatus 600.

More generally, as illustrated in FIG. 9, the method of FIGS. 1-8 is repeatedly

performed in order to provide a mono-diameter wellbore casing that includes overlapping wellbore casings 115 and 210a-210e. The wellbore casing 115, and 210a-210e preferably include outer annular layers of fluidic sealing material. In this manner, a mono-diameter wellbore casing may be formed within the subterranean formation that extends for tens of thousands of feet. More generally still, the teachings of FIGS. 1-9 may be used to form a mono-diameter wellbore casing, a pipeline, a structural support, or a tunnel within a subterranean formation at any orientation from the vertical to the horizontal.

In a preferred embodiment, the formation of a mono-diameter wellbore casing, as illustrated in FIGS. 1-9, is further provided as disclosed in one or more of the following: (1) U.S. patent 6,497,289, (2) Australian patent application AU-A-16417/00, (3) U.S. patent 6,823,937, (4) U.S. patent 6,328,113, (5) U.S. patent 6,640,903, (6) U.S. patent 6,568,471, (7) U.S. patent 6,575,240, (8) U.S. patent 6,557,640, (9) U.S. patent 6,604,763, (10) International patent application WO 01/04535, (11) International patent application WO 01/33037, (12) U.S. patent 6,564,875, (13) International patent application WO 01/26860, (14) U.S. patent application US 2003/0107217, (15) U.S. patent application US 2003/0121558, (16) International patent application WO 02/10551, (17) International patent application WO 02/10550, (18) International patent application WO 02/23007, (19) International patent application WO 02/29199, and (20) International patent application WO 02/053867, the disclosures of which are incorporated herein by reference.

In an alternative embodiment, the fluid passage 220 in the shoe 215 is omitted. In this manner, the pressurization of the region 230 is simplified. In an alternative embodiment, the annular body 515 of the fluidic sealing material is formed using conventional methods of injecting a hardenable fluidic sealing material into the annular region 310.

Referring to FIGS. 10-11, in an alternative embodiment, an apparatus 700 for forming a mono-diameter wellbore casing is positioned within the wellbore casing 115 that includes an expansion cone 705 having a fluid passage 705a that is coupled to a support member 710.

The expansion cone 705 preferably further includes a conical outer surface 705b for radially expanding and plastically deforming the overlapping portion of the tubular member 115 and the tubular member 210. In a preferred embodiment, the outside diameter of the

expansion cone 705 is substantially equal to the inside diameter of the pre-existing wellbore casing 115.

The support member 710 is coupled to a slip joint 715, and the slip joint is coupled to a support member 720. As will be recognized by persons having ordinary skill in the art, a slip joint permits relative movement between objects. Thus, in this manner, the expansion cone 705 and support member 710 may be displaced in the longitudinal direction relative to the support member 720. In a preferred embodiment, the slip joint 710 permits the expansion cone 705 and support member 710 to be displaced in the longitudinal direction relative to the support member 720 for a distance greater than or equal to the axial length of the tubular member 210. In this manner, the expansion cone 705 may be used to plastically deform and radially expand the overlapping portion of the tubular member 115 and the tubular member 210 without having to reposition the support member 720.

The slip joint 715 may be any number of conventional commercially available slip joints that include a fluid passage for conveying fluidic materials through the slip joint. In a preferred embodiment, the slip joint 715 is a pumper sub commercially available from Bowen Oil Tools in order to optimally provide elongation of the drill string.

The support member 710, slip joint 715, and support member 720 further include fluid passages 710a, 715a, and 720a, respectively, that are fluidicly coupled to the fluid passage 705a. During operation, the fluid passages 705a, 710a, 715a, and 720a preferably permit fluidic materials 725 displaced by the expansion cone 705 to be conveyed to a location above the apparatus 700. In this manner, operating pressures within the subterranean formation 105 below the expansion cone are minimized.

The support member 720 further preferably includes a fluid passage 720b that permits fluidic materials 730 to be conveyed into an annular region 735 surrounding the support member 710, the slip joint 715, and the support member 720 and bounded by the expansion cone 705 and a conventional packer 740 that is coupled to the support member 720. In this manner, the annular region 735 may be pressurized by the injection of the fluids 730 thereby causing the expansion cone 705 to be displaced in the longitudinal direction relative to the support member 720 to thereby plastically deform and radially expand the overlapping portion of the tubular member 115 and the tubular member 210.

During operation, as illustrated in FIG. 10, in a preferred embodiment, the apparatus

700 is positioned within the preexisting casing 115 with the bottom surface of the expansion cone 705 proximate the top of the tubular member 210. During placement of the apparatus 700 within the preexisting casing 115, fluidic materials 725 within the casing are conveyed out of the casing through the fluid passages 705a, 710a, 715a, and 720a. In this manner, surge pressures within the wellbore 100 are minimized.

The packer 740 is then operated in a well-known manner to fluidicly isolate the annular region 735 from the annular region above the packer. The fluidic material 730 is then injected into the annular region 735 using the fluid passage 720b. Continued injection of the fluidic material 730 into the annular region 735 preferably pressurizes the annular region and thereby causes the expansion cone 705 and support member 710 to be displaced in the longitudinal direction relative to the support member 720.

As illustrated in FIG. 11, in a preferred embodiment, the longitudinal displacement of the expansion cone 705 in turn plastically deforms and radially expands the overlapping portion of the tubular member 115 and the tubular member 210. In this manner, a mono-diameter wellbore casing is formed that includes the overlapping wellbore casings 115 and 210. The apparatus 700 may then be removed from the wellbore 100 by releasing the packer 740 from engagement with the wellbore casing 115, and lifting the apparatus 700 out of the wellbore 100.

In an alternative embodiment of the apparatus 700, the fluid passage 720b is provided within the packer 740 in order to enhance the operation of the apparatus 700.

In an alternative embodiment of the apparatus 700, the fluid passages 705a, 710a, 715a, and 720a are omitted. In this manner, in a preferred embodiment, the region of the wellbore 100 below the expansion cone 705 is pressurized and one or more regions of the subterranean formation 105 are fractured to enhance the oil and/or gas recovery process.

Referring to FIGS. 12-15, in an alternative embodiment, an apparatus 800 is positioned within the wellbore casing 115 that includes an expansion cone 805 having a fluid passage 805a that is releasably coupled to a releasable coupling 810 having fluid passage 810a.

The fluid passage 805a is preferably adapted to receive a conventional ball, plug, or other similar device for sealing off the fluid passage. The expansion cone 805 further includes a conical outer surface 805b for radially expanding and plastically deforming the

overlapping portion of the tubular member 115 and the tubular member 210. In a preferred embodiment, the outside diameter of the expansion cone 805 is substantially equal to the inside diameter of the pre-existing wellbore casing 115.

The releasable coupling 810 may be any number of conventional commercially available releasable couplings that include a fluid passage for conveying fluidic materials through the releasable coupling. In a preferred embodiment, the releasable coupling 810 is a safety joint commercially available from Halliburton in order to optimally release the expansion cone 805 from the support member 815 at a predetermined location.

A support member 815 is coupled to the releasable coupling 810 that includes a fluid passage 815a. The fluid passages 805a, 810a and 815a are fluidicly coupled. In this manner, fluidic materials may be conveyed into and out of the wellbore 100.

A packer 820 is movably and sealingly coupled to the support member 815. The packer may be any number of conventional packers. In a preferred embodiment, the packer 820 is a commercially available burst preventer (BOP) in order to optimally provide a sealing member.

During operation, as illustrated in FIG. 12, in a preferred embodiment, the apparatus 800 is positioned within the preexisting casing 115 with the bottom surface of the expansion cone 805 proximate the top of the tubular member 210. During placement of the apparatus 800 within the preexisting casing 115, fluidic materials 825 within the casing are conveyed out of the casing through the fluid passages 805a, 810a, and 815a. In this manner, surge pressures within the wellbore 100 are minimized. The packer 820 is then operated in a well-known manner to fluidicly isolate a region 830 within the casing 115 between the expansion cone 805 and the packer 820 from the region above the packer.

In a preferred embodiment, as illustrated in FIG. 13, the releasable coupling 810 is then released from engagement with the expansion cone 805 and the support member 815 is moved away from the expansion cone. A fluidic material 835 may then be injected into the region 830 through the fluid passages 810a and 815a. The fluidic material 835 may then flow into the region of the wellbore 100 below the expansion cone 805 through the valveable passage 805b. Continued injection of the fluidic material 835 may thereby pressurize and fracture regions of the formation 105 below the tubular member 210. In this manner, the recovery of oil and/or gas from the formation 105 may be enhanced.

In a preferred embodiment, as illustrated in FIG. 14, a plug, ball, or other similar valve device 840 may then be positioned in the valveable passage 805a by introducing the valve device into the fluidic material 835. In this manner, the region 830 may be fluidicly isolated from the region below the expansion cone 805. Continued injection of the fluidic material 835 may then pressurize the region 830 thereby causing the expansion cone 805 to be displaced in the longitudinal direction.

In a preferred embodiment, as illustrated in FIG. 15, the longitudinal displacement of the expansion cone 805 plastically deforms and radially expands the overlapping portion of the pre-existing wellbore casing 115 and the tubular member 210. In this manner, a mono-diameter wellbore casing is formed that includes the pre-existing wellbore casing 115 and the tubular member 210. Upon completing the radial expansion process, the support member 815 may be moved toward the expansion cone 805 and the expansion cone may be re-coupled to the releasable coupling device 810. The packer 820 may then be decoupled from the wellbore casing 115, and the expansion cone 805 and the remainder of the apparatus 800 may then be removed from the wellbore 100.

In a preferred embodiment, the displacement of the expansion cone 805 also pressurizes the region within the tubular member 210 below the expansion cone. In this manner, the subterranean formation surrounding the tubular member 210 may be elastically or plastically compressed thereby enhancing the structural properties of the formation.

A method of creating a mono-diameter wellbore casing in a borehole located in a subterranean formation including a preexisting wellbore casing has been described that includes installing a tubular liner and a first expansion cone in the borehole, injecting a fluidic material into the borehole, pressurizing a portion of an interior region of the tubular liner below the first expansion cone, radially expanding at least a portion of the tubular liner in the borehole by extruding at least a portion of the tubular liner off of the first expansion cone, and radially expanding at least a portion of the preexisting wellbore casing and the tubular liner using a second expansion cone. In a preferred embodiment, radially expanding at least a portion of the preexisting wellbore casing and the tubular liner using the second expansion cone includes displacing the second expansion cone in a longitudinal direction, and permitting fluidic materials displaced by the second expansion cone to be removed. In a preferred embodiment, displacing the second expansion cone in a longitudinal direction

includes applying fluid pressure to the second expansion cone. In a preferred embodiment, radially expanding at least a portion of the preexisting wellbore casing and the tubular liner using the second expansion cone includes displacing the second expansion cone in a longitudinal direction, and compressing at least a portion of the subterranean formation using fluid pressure. In a preferred embodiment, displacing the second expansion cone in a longitudinal direction includes applying fluid pressure to the second expansion cone. In a preferred embodiment, injecting a hardenable fluidic sealing material into an annulus between the tubular liner and the borehole.

An apparatus for forming a mono-diameter wellbore casing in a borehole located in a subterranean formation including a preexisting wellbore casing has also been described that includes means for installing a tubular liner and a first expansion cone in the borehole, means for injecting a fluidic material into the borehole, means for pressurizing a portion of an interior region of the tubular liner below the first expansion cone, means for radially expanding at least a portion of the tubular liner in the borehole by extruding at least a portion of the tubular liner off of the first expansion cone, and means for radially expanding at least a portion of the preexisting wellbore casing and the tubular liner using a second expansion cone. In a preferred embodiment, the means for radially expanding at least a portion of the preexisting wellbore casing and the tubular liner using the second expansion cone includes means for displacing the second expansion cone in a longitudinal direction, and means for permitting fluidic materials displaced by the second expansion cone to be removed. In a preferred embodiment, the means for displacing the second expansion cone in a longitudinal direction includes means for applying fluid pressure to the second expansion cone. In a preferred embodiment, the means for radially expanding at least a portion of the preexisting wellbore casing and the tubular liner using the second expansion cone includes means for displacing the second expansion cone in a longitudinal direction, and means for compressing at least a portion of the subterranean formation using fluid pressure. In a preferred embodiment, the means for displacing the second expansion cone in a longitudinal direction includes means for applying fluid pressure to the second expansion cone. In a preferred embodiment, the apparatus further includes means for injecting a hardenable fluidic sealing material into an annulus between the tubular liner and the borehole.

A method of joining a second tubular member to a first tubular member positioned within a subterranean formation, the first tubular member having an inner diameter greater than an outer diameter of the second tubular member has also been described that includes positioning a first expansion cone within an interior region of the second tubular member, pressurizing a portion of the interior region of the second tubular member adjacent to the first expansion cone, extruding at least a portion of the second tubular member off of the first expansion cone into engagement with the first tubular member, and radially expanding at least a portion of the first tubular member and the second tubular member using a second expansion cone. In a preferred embodiment, radially expanding at least a portion of the first tubular member and the second tubular member using the second expansion cone includes displacing the second expansion cone in a longitudinal direction, and permitting fluidic materials displaced by the second expansion cone to be removed. In a preferred embodiment, displacing the second expansion cone in a longitudinal direction includes applying fluid pressure to the second expansion cone. In a preferred embodiment, radially expanding at least a portion of the first and second tubular members using the second expansion cone includes displacing the second expansion cone in a longitudinal direction, and compressing at least a portion of the subterranean formation using fluid pressure. In a preferred embodiment, displacing the second expansion cone in a longitudinal direction includes applying fluid pressure to the second expansion cone. In a preferred embodiment, the method further includes injecting a hardenable fluidic sealing material into an annulus around the second tubular member.

An apparatus for joining a second tubular member to a first tubular member positioned within a subterranean formation, the first tubular member having an inner diameter greater than an outer diameter of the second tubular member, has also been described that includes means for positioning a first expansion cone within an interior region of the second tubular member, means for pressurizing a portion of the interior region of the second tubular member adjacent to the first expansion cone, means for extruding at least a portion of the second tubular member off of the first expansion cone into engagement with the first tubular member, and means for radially expanding at least a portion of the first tubular member and the second tubular member using a second expansion cone. In a preferred embodiment, the means for radially expanding at least a

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portion of the first tubular member and the second tubular member using the second expansion cone includes means for displacing the second expansion cone in a longitudinal direction, and means for permitting fluidic materials displaced by the second expansion cone to be removed. In a preferred embodiment, the means for displacing the second expansion cone in a longitudinal direction includes means for applying fluid pressure to the second expansion cone. In a preferred embodiment, the means for radially expanding at least a portion of the first tubular member and the second tubular member using the second expansion cone includes means for displacing the second expansion cone in a longitudinal direction, and means for compressing at least a portion of the subterranean formation using fluid pressure. In a preferred embodiment, the means for displacing the second expansion cone in a longitudinal direction includes means for applying fluid pressure to the second expansion cone. In a preferred embodiment, the apparatus further includes means for injecting a hardenable fluidic sealing material into an annulus around the second tubular member.

An apparatus has also been described that includes a subterranean formation including a borehole, a wellbore casing coupled to the borehole, and a tubular liner coupled to the first tubular member. The inside diameters of the wellbore casing and the tubular liner are substantially equal, and the tubular liner is coupled to the wellbore casing by a method that includes installing the tubular liner and a first expansion cone in the borehole, injecting a fluidic material into the borehole, pressurizing a portion of an interior region of the tubular liner below the first expansion cone, radially expanding at least a portion of the tubular liner in the borehole by extruding at least a portion of the tubular liner off of the first expansion cone, and radially expanding at least a portion of the wellbore casing and the tubular liner using a second expansion cone. In a preferred embodiment, radially expanding at least a portion of the wellbore casing and the tubular liner using the second expansion cone includes displacing the second expansion cone in a longitudinal direction, and permitting fluidic materials displaced by the second expansion cone to be removed. In a preferred embodiment, displacing the second expansion cone in a longitudinal direction includes applying fluid pressure to the second expansion cone. In a preferred embodiment, radially expanding at least a portion of the wellbore casing and the tubular liner using the second expansion cone includes displacing the second expansion cone in a longitudinal

direction and compressing at least a portion of the subterranean formation using fluid pressure. In a preferred embodiment, displacing the second expansion cone in a longitudinal direction includes applying fluid pressure to the second expansion cone. In a preferred embodiment, the annular layer of the fluidic sealing material is formed by a method that includes injecting a hardenable fluidic sealing material into an annulus between the tubular liner and the borehole.

An apparatus has also been described that includes a subterranean formation including a borehole, a first tubular member coupled to the borehole, and a second tubular member coupled to the wellbore casing. The inside diameters of the first and second tubular members are substantially equal, and the second tubular member is coupled to the first tubular member by a method that includes installing the second tubular member and a first expansion cone in the borehole, injecting a fluidic material into the borehole, pressurizing a portion of an interior region of the second tubular member below the first expansion cone, radially expanding at least a portion of the second tubular member in the borehole by extruding at least a portion of the second tubular member off of the first expansion cone, and radially expanding at least a portion of the first tubular member and the second tubular member using a second expansion cone. In a preferred embodiment, radially expanding at least a portion of the first and second tubular members using the second expansion cone includes displacing the second expansion cone in a longitudinal direction, and permitting fluidic materials displaced by the second expansion cone to be removed. In a preferred embodiment, displacing the second expansion cone in a longitudinal direction includes applying fluid pressure to the second expansion cone. In a preferred embodiment, radially expanding at least a portion of the first and second tubular members using the second expansion cone includes displacing the second expansion cone in a longitudinal direction, and compressing at least a portion of the subterranean formation using fluid pressure. In a preferred embodiment, displacing the second expansion cone in a longitudinal direction includes applying fluid pressure to the second expansion cone. In a preferred embodiment, the annular layer of the fluidic sealing material is formed by a method that includes injecting a hardenable fluidic sealing material into an annulus between the first tubular member and the borehole.

An apparatus for radially expanding an overlapping joint between a wellbore casing

and a tubular liner has also been described that includes a tubular support including first and second passages, a sealing member coupled to the tubular support, a slip joint coupled to the tubular support including a third passage fluidicly coupled to the second passage, and an expansion cone coupled to the slip joint including a fourth passage fluidicly coupled to the third passage.

A method of radially expanding an overlapping joint between a wellbore casing and a tubular liner has also been described that includes positioning an expansion cone within the wellbore casing above the overlapping joint, sealing off an annular region within the wellbore casing above the expansion cone, displacing the expansion cone by pressurizing the annular region, and removing fluidic materials displaced by the expansion cone from the tubular liner. In a preferred embodiment, the method further includes supporting the expansion cone during the displacement of the expansion cone.

An apparatus for radially expanding an overlapping joint between a wellbore casing and a tubular liner has also been described that includes means for positioning an expansion cone within the wellbore casing above the overlapping joint, means for sealing off an annular region within the wellbore casing above the expansion cone, means for displacing the expansion cone by pressurizing the annular region, and means for removing fluidic materials displaced by the expansion cone from the tubular liner. In a preferred embodiment, the apparatus further includes means for supporting the expansion cone during the displacement of the expansion cone.

An apparatus for radially expanding an overlapping joint between a wellbore casing and a tubular liner has also been described that includes a tubular support including a first passage, a sealing member coupled to the tubular support, a releasable latching member coupled to the tubular support, and an expansion cone releasably coupled to the releasable latching member including a second passage fluidicly coupled to the first passage.

A method of radially expanding an overlapping joint between a wellbore casing and a tubular liner has also been described that includes positioning an expansion cone within the wellbore casing above the overlapping joint, sealing off a region within the wellbore casing above the expansion cone, releasing the expansion cone, and displacing the expansion cone by pressurizing the annular region. In a preferred embodiment, the method further includes pressurizing the interior of the tubular liner.

An apparatus for radially expanding an overlapping joint between a wellbore casing and a tubular liner has also been described that includes means for positioning an expansion cone within the wellbore casing above the overlapping joint, means for sealing off a region within the wellbore casing above the expansion cone, means for releasing the expansion cone, and means for displacing the expansion cone by pressurizing the annular region. In a preferred embodiment, the apparatus further includes means for pressurizing the interior of the tubular liner.

An apparatus for radially expanding an overlapping joint between first and second tubular members has also been described that includes a tubular support including first and second passages, a sealing member coupled to the tubular support, a slip joint coupled to the tubular support including a third passage fluidicly coupled to the second passage, and an expansion cone coupled to the slip joint including a fourth passage fluidicly coupled to the third passage.

A method of radially expanding an overlapping joint between first and second tubular members has also been described that includes positioning an expansion cone within the first tubular member above the overlapping joint, sealing off an annular region within the first tubular member above the expansion cone, displacing the expansion cone by pressurizing the annular region, and removing fluidic materials displaced by the expansion cone from the second tubular member. In a preferred embodiment, the method further includes supporting the expansion cone during the displacement of the expansion cone.

An apparatus for radially expanding an overlapping joint between first and second tubular members has also been described that includes means for positioning an expansion cone within the first tubular member above the overlapping joint, means for sealing off an annular region within the first tubular member above the expansion cone, means for displacing the expansion cone by pressurizing the annular region, and means for removing fluidic materials displaced by the expansion cone from the second tubular member. In a preferred embodiment, the apparatus further includes means for supporting the expansion cone during the displacement of the expansion cone.

An apparatus for radially expanding an overlapping joint between first and second tubular members has also been described that includes a tubular support including a first passage, a sealing member coupled to the tubular support, a releasable latching member

coupled to the tubular support, and an expansion cone releasably coupled to the releasable latching member including a second passage fluidicly coupled to the first passage.

A method of radially expanding an overlapping joint between first and second tubular members has also been described that includes positioning an expansion cone within the first tubular member above the overlapping joint, sealing off a region within the first tubular member above the expansion cone, releasing the expansion cone, and displacing the expansion cone by pressurizing the annular region. In a preferred embodiment, the method further includes pressurizing the interior of the second tubular member.

An apparatus for radially expanding an overlapping joint between first and second tubular members has also been described that includes means for positioning an expansion cone within the first tubular member above the overlapping joint, means for sealing off a region within the first tubular member above the expansion cone, means for releasing the expansion cone, and means for displacing the expansion cone by pressurizing the annular region. In a preferred embodiment, the apparatus further includes means for pressurizing the interior of the second tubular member.

Although illustrative embodiments of the invention have been shown and described, a wide range of modification, changes and substitution is contemplated in the foregoing disclosure. In some instances, some features of the present invention may be employed without a corresponding use of the other features. Accordingly, it is appropriate that the appended claims be construed broadly and in a manner consistent with the scope of the invention.

Throughout this specification and the claims which follow, unless the context requires otherwise, the word "comprise", and variations such as "comprises" and "comprising", will be understood to imply the inclusion of a stated integer or step or group of integers or steps but not the exclusion of any other integer or step or group of integers or steps.

The reference in this specification to any prior publication (or information derived from it), or to any matter which is known, is not, and should not be taken as an acknowledgment or admission or any form of suggestion that that prior publication (or information derived from it) or known matter forms part of the common general knowledge in the field of endeavour to which this specification relates.

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THE CLAIMS DEFINING THE INVENTION ARE AS FOLLOWS:

1. A method of creating a mono-diameter wellbore casing in a borehole located in a subterranean formation including a preexisting wellbore casing, comprising:

installing a tubular liner and a first expansion cone in the borehole;

injecting a fluidic material into the borehole;

pressurizing a portion of an interior region of the tubular liner below the first expansion cone;

radially expanding at least a portion of the tubular liner in the borehole by extruding at least a portion of the tubular liner off the first expansion cone; and

radially expanding at least a portion of the preexisting wellbore casing and the tubular liner using a second expansion cone.

2. The method of claim 1, wherein radially expanding at least a portion of the preexisting wellbore casing and the tubular liner using the second expansion cone comprises:

displacing the second expansion cone in a longitudinal direction; and

permitting fluidic materials displaced by the second expansion cone to be removed.

3. The method of claim 2, wherein displacing the second expansion cone in a longitudinal direction comprises:

applying fluid pressure to the second expansion cone.

4. The method of claim 1, wherein radially expanding at least a portion of the preexisting wellbore casing and the tubular liner using the second expansion cone comprises:

displacing the second expansion cone in a longitudinal direction; and

compressing at least a portion of the subterranean formation using fluid pressure.

5. The method of claim 4, wherein displacing the second expansion cone in a

longitudinal direction comprises:

applying fluid pressure to the second expansion cone.

6. The method of claim 1, further comprising:

injecting a hardenable fluidic sealing material into an annulus between the tubular liner and the borehole.

7. The method of claim 1, wherein the inside diameter of the portion of the tubular liner radially expanded by the first expansion cone is equal to the inside diameter of the portion of the preexisting wellbore casing that was not radially expanded by the second expansion cone.

8. Apparatus for forming a mono-diameter wellbore casing in a borehole located in a subterranean formation including a preexisting wellbore casing, comprising:

means for installing a tubular liner and a first expansion cone in the borehole;

means for injecting a fluidic material into the borehole;

means for pressurizing a portion of an interior region of the tubular liner below the first expansion cone;

means for radially expanding at least a portion of the tubular liner in the borehole by extruding at least a portion of the tubular liner off the first expansion cone; and

means for radially expanding at least a portion of the preexisting wellbore casing and the tubular liner using a second expansion cone.

9. The apparatus of claim 8, wherein the means for radially expanding at least a portion of the preexisting wellbore casing and the tubular liner using the second expansion cone comprises:

means for displacing the second expansion cone in a longitudinal direction; and

means for permitting fluidic materials displaced by the second expansion cone to be removed.

tubulars coupled to and interleaved among the slotted tubulars, each intermediate solid tubular including one or more external annular seals, and a shoe coupled to one of the slotted tubulars.

A method of isolating a first subterranean zone from a second subterranean zone in a wellbore has also been described that includes positioning one or more primary solid tubulars within the wellbore, the primary solid tubulars traversing the first subterranean zone, positioning one or more slotted tubulars within the wellbore, the slotted tubulars traversing the second subterranean zone, fluidicly coupling the slotted tubulars and the solid tubulars, and preventing the passage of fluids from the first subterranean zone to the second subterranean zone within the wellbore external to the solid and slotted tubulars.

A method of extracting materials from a producing subterranean zone in a wellbore, at least a portion of the wellbore including a casing, has also been described that includes positioning one or more primary solid tubulars within the wellbore, fluidicly coupling the primary solid tubulars with the casing, positioning one or more slotted tubulars within the wellbore, the slotted tubulars traversing the producing subterranean zone, fluidicly coupling the slotted tubulars with the solid tubulars, fluidicly isolating the producing subterranean zone from at least one other subterranean zone within the wellbore, and fluidicly coupling at least one of the slotted tubulars from the producing subterranean zone. In a preferred embodiment, the method further includes controllably fluidicly decoupling at least one of the slotted tubulars from at least one other of the slotted tubulars.

A method of creating a casing in a borehole while also drilling the borehole also has been described that includes installing a tubular liner, a mandrel, and a drilling assembly in the borehole. A fluidic material is injected within the tubular liner, mandrel and drilling assembly. At least a portion of the tubular liner is radially expanded while the borehole is drilled using the drilling assembly. In a preferred embodiment, the injecting includes injecting the fluidic material within an expandable chamber. In a preferred embodiment, the injecting includes injecting

hardenable fluidic sealing material into an annular region located between the borehole and the exterior of the tubular liner. In a preferred embodiment, the injecting of the hardenable fluidic sealing material is provided at operating pressures and flow rates ranging from about 0 to 5,000 psi and 0 to 1,500 gallons/min. In a preferred embodiment, the injecting of the fluidic material is provided at operating pressures and flow rates ranging from about 500 to 9,000 psi and 40 to 3,000 gallons/min. In a preferred embodiment, the injecting of the fluidic material is provided at reduced operating pressures and flow rates during an end portion of the radial expansion. In a preferred embodiment, the method further includes curing at least a portion of the fluidic material; and removing at least a portion of the cured fluidic material located within the tubular liner. In a preferred embodiment, the method further includes overlapping the tubular liner with an existing wellbore casing. In a preferred embodiment, the method further includes sealing the overlap between the tubular liner and the existing wellbore casing. In a preferred embodiment, the method further includes supporting the extruded tubular liner using the overlap with the existing wellbore casing. In a preferred embodiment, the method further includes testing the integrity of the seal in the overlap between the tubular liner and the existing wellbore casing. In a preferred embodiment, the method further includes lubricating the surface of the mandrel. In a preferred embodiment, the method further includes absorbing shock. In a preferred embodiment, the method further includes catching the mandrel upon the completion of the extruding. In a preferred embodiment, the method further includes expanding the mandrel in a radial direction. In a preferred embodiment, the method further includes drilling out the mandrel. In a preferred embodiment, the method further includes supporting the mandrel with coiled tubing. In a preferred embodiment, the wall thickness of the tubular member is variable. In a preferred embodiment, the mandrel is coupled to a drillable shoe.

An apparatus has also been described that includes a support member, the support member including a first fluid passage; a mandrel coupled to the support

member, the mandrel including: a second fluid passage; a tubular member coupled to the mandrel; and a shoe coupled to the tubular liner, the shoe including a third fluid passage; and a drilling assembly coupled to the shoe; wherein the first, second and third fluid passages and the drilling assembly are operably coupled. In a preferred embodiment, the support member further includes: a pressure relief passage; and a flow control valve coupled to the first fluid passage and the pressure relief passage. In a preferred embodiment, the support member further includes a shock absorber. In a preferred embodiment, the support member includes one or more sealing members adapted to prevent foreign material from entering an interior region of the tubular member. In a preferred embodiment, the support member includes one or more stabilizers. In a preferred embodiment, the mandrel is expandable. In a preferred embodiment, the tubular member is fabricated from materials selected from the group consisting of Oilfield Country Tubular Goods, automotive grade steel, plastic and chromium steel. In a preferred embodiment, the tubular member has inner and outer diameters ranging from about 0.75 to 47 inches and 1.05 to 48 inches, respectively. In a preferred embodiment, the tubular member has a plastic yield point ranging from about 40,000 to 135,000 psi. In a preferred embodiment, the tubular member includes one or more sealing members at an end portion. In a preferred embodiment, the tubular member includes one or more pressure relief holes at an end portion. In a preferred embodiment, the tubular member includes a catching member at an end portion for slowing down movement of the mandrel. In a preferred embodiment, the support member comprises coiled tubing. In a preferred embodiment, at least a portion of the mandrel and shoe are drillable. In a preferred embodiment, the wall thickness of the tubular member in an area adjacent to the mandrel is less than the wall thickness of the tubular member in an area that is not adjacent to the mandrel. In a preferred embodiment, the apparatus further includes an expandable chamber. In a preferred embodiment, the expandable chamber is approximately cylindrical. In a preferred embodiment, the expandable chamber is approximately annular.

A method of forming an underground pipeline within an underground tunnel including at least a first tubular member and a second tubular member, the first tubular member having an inner diameter greater than an outer diameter of the second tubular member, has also been described that includes positioning the first tubular member within the tunnel; positioning the second tubular member within the tunnel in an overlapping relationship with the first tubular member; positioning a mandrel and a drilling assembly within an interior region of the second tubular member; injecting a fluidic material within the mandrel, drilling assembly and the second tubular member; extruding at least a portion of the second tubular member off of the mandrel into engagement with the first tubular member; and drilling the tunnel. In a preferred embodiment, the injecting of the fluidic material is provided at operating pressures ranging from about 500 to 9,000 psi. In a preferred embodiment, the injecting of the fluidic material is provided at reduced operating pressures during a latter portion of the extruding. In a preferred embodiment, the method further includes sealing the interface between the first and second tubular members. In a preferred embodiment, the method further includes supporting the extruded second tubular member using the interface with the first tubular member. In a preferred embodiment, the method further includes lubricating the surface of the mandrel. In a preferred embodiment, the method further includes absorbing shock. In a preferred embodiment, the method further includes expanding the mandrel in a radial direction. In a preferred embodiment, the method further includessealing the interface between the first and second tubular members. In a preferred embodiment, the method further includes supporting the extruded second tubular member using the first tubular member. In a preferred embodiment, the method further includes testing the integrity of the seal in the interface between the first tubular member and the second tubular member. In a preferred embodiment, the method further includes catching the mandrel upon the completion of the extruding. In a preferred embodiment, the method further includes drilling out the mandrel. In a preferred embodiment, the method further includes supporting the mandrel with coiled tubing.

In a preferred embodiment, the method further includes coupling the mandrel to a drillable shoe. In a preferred embodiment, the fluidic material is injected into an expandable chamber. In a preferred embodiment, the expandable chamber is substantially cylindrical. In a preferred embodiment, the expandable chamber is substantially annular. An apparatus has also been described that includes a wellbore, the wellbore formed by the process of drilling the wellbore; and a tubular liner positioned within the wellbore, the tubular liner formed by the process of extruding the tubular liner off of a mandrel while drilling the wellbore. In a preferred embodiment, the tubular liner is formed by the process of: placing the tubular liner and mandrel within the wellbore; and pressurizing an interior portion of the tubular liner. In a preferred embodiment, the interior portion of the tubular liner is pressurized at pressures ranging from about 500 to 9,000 psi. In a preferred embodiment, the tubular liner is formed by the process of: placing the tubular liner and mandrel within the wellbore; and pressurizing an interior portion of the mandrel. In a preferred embodiment, the interior portion of the mandrel is pressurized at pressures ranging from about 500 to 9,000 psi. In a preferred embodiment, the apparatus further includes an annular body of a cured fluidic material coupled to the tubular liner. In a preferred embodiment, the annular body of a cured fluidic sealing material is formed by the process of: injecting a body of hardenable fluidic sealing material into an annular region external of the tubular liner. In a preferred embodiment, the tubular liner overlaps with an existing wellbore casing. In a preferred embodiment, the apparatus further includes a seal positioned in the overlap between the tubular liner and the existing wellbore casing. In a preferred embodiment, the tubular liner is supported by the overlap with the existing wellbore casing. In a preferred embodiment, the process of extruding the tubular liner includes the pressurizing of an expandable chamber. In a preferred embodiment, the expandable chamber is substantially cylindrical. In a preferred embodiment, the expandable chamber is substantially annular.

A method of forming a wellbore casing in a wellbore has also been described that includes drilling out the wellbore while forming the wellbore casing. In a preferred embodiment, the forming includes: expanding a tubular member in the radial direction. In a preferred embodiment, the expanding includes: displacing a mandrel relative to the tubular member. In a preferred embodiment, the displacing includes: expanding an expandable chamber. In a preferred embodiment, the expandable chamber comprises a cylindrical chamber. In a preferred embodiment, the expandable chamber comprises an annular chamber.

A method of expanding a tubular member has also been described that includes placing a mandrel within the tubular member, pressurizing an annular region within the tubular member, and displacing the mandrel with respect to the tubular member. In a preferred embodiment, the method further includes removing fluids within the tubular member that are displaced by the displacement of the mandrel. In a preferred embodiment, the removed fluids pass inside the annular region. In a preferred embodiment, the volume of the annular region increases. In a preferred embodiment, the method further includes sealing off the annular region. In a preferred embodiment, sealing off the annular region includes sealing a stationary member and sealing a non-stationary member. In a preferred embodiment, the method further includes conveying fluids in opposite directions. In a preferred embodiment, the method further includes conveying a pressurized fluid and a non-pressurized fluid in opposite directions. In a preferred embodiment, the pressurizing is provided at operating pressures ranging from about 0 to 9,000 psi. In a preferred embodiment, the pressurizing is provided at flow rates ranging from about 0 to 3,000 gallons/minute.

A method of coupling a tubular member to preexisting structure has also been described that includes positioning the tubular member in an overlapping relationship to the preexisting structure, placing a mandrel within the tubular member, pressurizing an annular region within the tubular member, and displacing the mandrel with respect to the tubular member. In a preferred embodiment, the

method further includes removing fluids within the tubular member that are displaced by the displacement of the mandrel. In a preferred embodiment, the removed fluids pass inside the annular region. In a preferred embodiment, the volume of the annular region increases. In a preferred embodiment, the method further includes sealing off the annular region. In a preferred embodiment, sealing off the annular region includes sealing a stationary member and sealing a non-stationary member. In a preferred embodiment, the method further includes conveying fluids in opposite directions. In a preferred embodiment, the method further includes conveying a pressurized fluid and a non-pressurized fluid in opposite directions. In a preferred embodiment, the pressurizing is provided at operating pressures ranging from about 0 to 9,000 psi. In a preferred embodiment, the pressurizing is provided at flow rates ranging from about 0 to 3,000 gallons/minute.

A method of repairing a defect in a preexisting structure using a tubular member has also been described that includes positioning the tubular member in an overlapping relationship to the defect in the preexisting structure, placing a mandrel within the tubular member, pressurizing an annular region within the tubular member, and displacing the mandrel with respect to the tubular member. In a preferred embodiment, the method further includes removing fluids within the tubular member that are displaced by the displacement of the mandrel. In a preferred embodiment, the removed fluids pass inside the annular region. In a preferred embodiment, the volume of the annular region increases. In a preferred embodiment, the method further includes sealing off the annular region. In a preferred embodiment, sealing off the annular region includes sealing a stationary member and sealing a non-stationary member. In a preferred embodiment, the method further includes conveying fluids in opposite directions. In a preferred embodiment, the method further includes conveying a pressurized fluid and a non-pressurized fluid in opposite directions. In a preferred embodiment, the pressurizing is provided at operating pressures ranging from about 0 to 9,000 psi. In a preferred

embodiment, the pressurizing is provided at flow rates ranging from about 0 to 3,000 gallons/minute. In a preferred embodiment, the method further includes sealing the interface between the preexisting structure and the tubular member at ends of the tubular member.

An apparatus for radially expanding a tubular member has also been described that includes a first tubular member, a second tubular member positioned within the first tubular member, a third tubular member movably coupled to and positioned within the second tubular member, a first annular sealing member for sealing an interface between the first and second tubular members, a second annular sealing member for sealing an interface between the second and third tubular members, and a mandrel positioned within the first tubular member and coupled to an end of the third tubular member. In a preferred embodiment, the apparatus further includes an annular chamber defined by the first tubular member, the second tubular member, the third tubular member, the first annular sealing member, the second annular sealing member, and the mandrel. In a preferred embodiment, the apparatus further includes an annular passage defined by the second tubular member and the third tubular member. In a preferred embodiment, the apparatus further includes a fluid passage contained within the third tubular member and the mandrel. In a preferred embodiment, the apparatus further includes one or more sealing members coupled to an exterior surface of the first tubular member. In a preferred embodiment, the apparatus further includes an annular chamber defined by the first tubular member, the second tubular member, the third tubular member, the first annular sealing member, the second annular sealing member, and the mandrel, and annular passage defined by the second tubular member and the third tubular member. In a preferred embodiment, the annular chamber and the annular passage are fluidicly coupled. In a preferred embodiment, the apparatus further includes one or more slips coupled to the exterior surface of the first tubular member. In a preferred embodiment, the mandrel includes a conical surface. In a preferred embodiment, the angle of attack of the conical surface ranges from about 10 to 30

degrees. In a preferred embodiment, the conical surface has a surface hardness ranging from about 58 to 62 Rockwell C.

An apparatus has also been described that includes a tubular member, a piston adapted to expand the diameter of the tubular member positioned within the tubular member, the piston including a passage for conveying fluids out of the tubular member, and an annular chamber defined by the piston and tubular member. In a preferred embodiment, the piston includes a conical surface. In a preferred embodiment, the angle of attack of the conical surface ranges from about 10 to 30 degrees. In a preferred embodiment, the conical surface has a surface hardness ranging from about 58 to 62 Rockwell C. In a preferred embodiment, the tubular member includes one or more sealing members coupled to the exterior surface of the tubular member.

A wellbore casing has also been described that includes a first tubular member and a second tubular member coupled to the first tubular member. The second tubular member is coupled to the first tubular member by the process of positioning the second tubular member in an overlapping relationship to the first tubular member, placing a mandrel within the second tubular member, pressurizing an annular region within the second tubular member, and displacing the mandrel with respect to the second tubular member. In a preferred embodiment, the wellbore casing further includes removing fluids within the second tubular member that are displaced by the displacement of the mandrel. In a preferred embodiment, the removed fluids pass inside the annular region. In a preferred embodiment, the volume of the annular region increases. In a preferred embodiment, the wellbore casing further includes sealing off the annular region. In a preferred embodiment, sealing off the annular region includes sealing a stationary member and sealing a non-stationary member. In a preferred embodiment, the wellbore casing further including conveying fluids in opposite directions. In a preferred embodiment, the wellbore casing further includes conveying a pressurized fluid and a non-pressurized fluid in opposite directions. In a preferred embodiment, the pressurizing is provided

at operating pressures ranging from about 0 to 9,000 psi. In a preferred embodiment, the pressurizing is provided at flow rates ranging from about 0 to 3,000 gallons/minute.

An apparatus has also been described that includes a preexisting structure and a tubular member coupled to the preexisting structure. The tubular member is coupled to the preexisting structure by the process of: positioning the tubular member in an overlapping relationship to the preexisting structure, placing a mandrel within the tubular member, pressurizing an annular region within the tubular member, and displacing the mandrel with respect to the tubular member. In a preferred embodiment, the apparatus further includes removing fluids within the tubular member that are displaced by the displacement of the mandrel. In a preferred embodiment, the removed fluids pass inside the annular region. In a preferred embodiment, the volume of the annular region increases. In a preferred embodiment, the apparatus further includes sealing off the annular region. In a preferred embodiment, sealing off the annular region includes sealing a stationary member and sealing a non-stationary member. In a preferred embodiment, the apparatus further includes conveying fluids in opposite directions. In a preferred embodiment, the apparatus further includes conveying a pressurized fluid and a non-pressurized fluid in opposite directions. In a preferred embodiment, the pressurizing is provided at operating pressures ranging from about 0 to 9,000 psi. In a preferred embodiment, the pressurizing is provided at flow rates ranging from about 0 to 3,000 gallons/minute.

An apparatus has also been described that includes a preexisting structure having a defective portion and a tubular member coupled to the defective portion of the preexisting structure. The tubular member is coupled to the defective portion of the preexisting structure by the process of: positioning the tubular member in an overlapping relationship to the defect in the preexisting structure, placing a mandrel within the tubular member, pressurizing an annular region within the tubular member, and displacing the mandrel with respect to the tubular member. In a

preferred embodiment, the apparatus further includes removing fluids within the tubular member that are displaced by the displacement of the mandrel. In a preferred embodiment, the removed fluids pass inside the annular region. In a preferred embodiment, the volume of the annular region increases. In a preferred embodiment, the apparatus further includes sealing off the annular region. In a preferred embodiment, sealing off the annular region includes sealing a stationary member and sealing a non-stationary member. In a preferred embodiment, the apparatus further includes conveying fluids in opposite directions. In a preferred embodiment, the apparatus further includes conveying a pressurized fluid and a non-pressurized fluid in opposite directions. In a preferred embodiment, the pressurizing is provided at operating pressures ranging from about 0 to 9,000 psi. In a preferred embodiment, the pressurizing is provided at flow rates ranging from about 0 to 3,000 gallons/minute. In a preferred embodiment, the apparatus further includes sealing the interface between the preexisting structure and the tubular member at ends of the tubular member.

A method of expanding a tubular member has also been described that includes placing a mandrel within the tubular member, pressurizing a region within the tubular member, and displacing the mandrel with respect to the tubular member. In a preferred embodiment, the pressurizing is provided at operating pressures ranging from about 0 to 9,000 psi. In a preferred embodiment, the pressurizing is provided at flow rates ranging from about 0 to 3,000 gallons/minute. In a preferred embodiment, the tubular member is expanded beginning at an upper portion of the tubular member.

A method of coupling a tubular member to preexisting structure has also been described that includes positioning the tubular member in an overlapping relationship to the preexisting structure, placing a mandrel within the tubular member, pressurizing an interior region within the tubular member, and displacing the mandrel with respect to the tubular member. In a preferred embodiment, the pressurizing is provided at operating pressures ranging from about 0 to 9,000 psi. In

a preferred embodiment, the pressurizing is provided at flow rates ranging from about 0 to 3,000 gallons/minute. In a preferred embodiment, the tubular member is expanded beginning at an upper portion of the tubular member.

A method of repairing a defect in a preexisting structure using a tubular member has also been described that includes positioning the tubular member in an overlapping relationship to the defect in the preexisting structure, placing a mandrel within the tubular member, pressurizing an interior region within the tubular member, and displacing the mandrel with respect to the tubular member. In a preferred embodiment, the pressurizing is provided at operating pressures ranging from about 0 to 9,000 psi. In a preferred embodiment, the pressurizing is provided at flow rates ranging from about 0 to 3,000 gallons/minute. In a preferred embodiment, the tubular member is expanded beginning at an upper portion of the tubular member. In a preferred embodiment, the method further includes sealing the interface between the preexisting structure and the tubular member at both ends of the tubular member.

An apparatus for radially expanding a tubular member has also been described that includes a first tubular member, a second tubular member coupled to the first tubular member, a third tubular member coupled to the second tubular member, and a mandrel positioned within the second tubular member and coupled to an end portion of the third tubular member. In a preferred embodiment, the mandrel includes a fluid passage having an inlet adapted to receive fluid stop member. In a preferred embodiment, the apparatus further includes one or more slips coupled to the exterior surface of the third tubular member. In a preferred embodiment, the mandrel includes a conical surface. In a preferred embodiment, the angle of attack of the conical surface ranges from about 10 to 30 degrees. In a preferred embodiment, the conical surface has a surface hardness ranging from about 58 to 62 Rockwell C. In a preferred embodiment, the average inside diameter of the second tubular member is greater than the average inside diameter of the third tubular member.

An apparatus has also been described that includes a tubular member, a piston adapted to expand the diameter of the tubular member positioned within the tubular member, the piston including a passage for conveying fluids out of the tubular member. In a preferred embodiment, the piston includes a conical surface. In a preferred embodiment, the angle of attack of the conical surface ranges from about 10 to 30 degrees. In a preferred embodiment, the conical surface has a surface hardness ranging from about 58 to 62 Rockwell C. In a preferred embodiment, the tubular member includes one or more sealing members coupled to the exterior surface of the tubular member.

A wellbore casing has also been described that includes a first tubular member and a second tubular member coupled to the first tubular member. The second tubular member is coupled to the first tubular member by the process of: positioning the second tubular member in an overlapping relationship to the first tubular member, placing a mandrel within the second tubular member, pressurizing an interior region within the second tubular member, and displacing the mandrel with respect to the second tubular member. In a preferred embodiment, the pressurizing is provided at operating pressures ranging from about 0 to 9,000 psi. In a preferred embodiment, the pressurizing is provided at flow rates ranging from about 0 to 3,000 gallons/minute.

An apparatus has also been described that includes a preexisting structure and a tubular member coupled to the preexisting structure. The tubular member is coupled to the preexisting structure by the process of: positioning the tubular member in an overlapping relationship to the preexisting structure, placing a mandrel within the tubular member, pressurizing an interior region within the tubular member, and displacing the mandrel with respect to the tubular member. In a preferred embodiment, the pressurizing is provided at operating pressures ranging from about 0 to 9,000 psi. In a preferred embodiment, the pressurizing is provided at flow rates ranging from about 0 to 3,000 gallons/minute.

An apparatus has also been described that includes a preexisting structure having a defective portion and a tubular member coupled to the defective portion of the preexisting structure. The tubular member is coupled to the defective portion of the preexisting structure by the process of: positioning the tubular member in an overlapping relationship to the defect in the preexisting structure, placing a mandrel within the tubular member, pressurizing an interior region within the tubular member, and displacing the mandrel with respect to the tubular member. In a preferred embodiment, the pressurizing is provided at operating pressures ranging from about 0 to 9,000 psi. In a preferred embodiment, the pressurizing is provided at flow rates ranging from about 0 to 3,000 gallons/minute. In a preferred embodiment, the apparatus further includes sealing the interface between the preexisting structure and the tubular member at both ends of the tubular member.

An apparatus also has been described that includes a first tubular member, a second tubular member, and a threaded connection for coupling the first tubular member to the second tubular member. The threaded connection includes one or more sealing members for sealing the interface between the first and second tubular members. In a preferred embodiment, the threaded connection comprises a pin and box threaded connection. In a preferred embodiment, the sealing members are positioned adjacent to an end portion of the threaded connection. In a preferred embodiment, one of the sealing members is positioned adjacent to an end portion of the threaded connection; and wherein another one of the sealing members is not positioned adjacent to an end portion of the threaded connection. In a preferred embodiment, a plurality of the sealing members are positioned adjacent to an end portion of the threaded connection.

An apparatus also has been described that includes a tubular assembly having a first tubular member, a second tubular member, and a threaded connection for coupling the first tubular member to the second tubular member. The threaded connection includes one or more sealing members for sealing the interface between the first and second tubular members. The tubular assembly is formed by the process

of radially expanding the tubular assembly. In a preferred embodiment, the threaded connection comprises a pin and box threaded connection. In a preferred embodiment, the sealing members are positioned adjacent to an end portion of the threaded connection. In a preferred embodiment, one of the sealing members is positioned adjacent to an end portion of the threaded connection; and wherein another one of the sealing members is not positioned adjacent to an end portion of the threaded connection. In a preferred embodiment, a plurality of the sealing members are positioned adjacent to an end portion of the threaded connection.

An apparatus also has been described that includes a tubular member and a mandrel positioned within the tubular member including a conical surface have an angle of attack ranging from about 10 to 30 degrees. In a preferred embodiment, the tubular member includes a first tubular member, a second tubular member, and a threaded connection for coupling the first tubular member to the second tubular member. The threaded connection includes one or more sealing members for sealing the interface between the first and second tubular members. In a preferred embodiment, the threaded connection comprises a pin and box threaded connection. In a preferred embodiment, the sealing members are positioned adjacent to an end portion of the threaded connection. In a preferred embodiment, one of the sealing members is positioned adjacent to an end portion of the threaded connection; and wherein another one of the sealing members is not positioned adjacent to an end portion of the threaded connection. In a preferred embodiment, a plurality of the sealing members are positioned adjacent to an end portion of the threaded connection.

An expansion cone for expanding a tubular member has also been described that includes a housing including a tapered first end and a second end, one or more grooves formed in the outer surface of the tapered first end, and one or more axial flow passages fluidicly coupled to the circumferential grooves. In a preferred embodiment, the grooves comprise circumferential grooves. In a preferred embodiment, the grooves comprise spiral grooves. In a preferred embodiment, the

grooves are concentrated around the axial midpoint of the tapered portion of the housing. In a preferred embodiment, the axial flow passages comprise axial grooves. In a preferred embodiment, the axial grooves are spaced apart by at least about 3 inches in the circumferential direction. In a preferred embodiment, the axial grooves extend from the tapered first end of the body to the grooves. In a preferred embodiment, the axial grooves extend from the second end of the body to the grooves. In a preferred embodiment, the axial grooves extend from the tapered first end of the body to the second end of the body. In a preferred embodiment, the flow passages are positioned within the housing of the expansion cone. In a preferred embodiment, the flow passages extend from the tapered first end of the body to the grooves. In a preferred embodiment, the flow passages extend from the tapered first end of the body to the second end of the body. In a preferred embodiment, the flow passages extend from the second end of the body to the grooves. In a preferred embodiment, one or more of the flow passages include inserts having restricted flow passages. In a preferred embodiment, one or more of the flow passages include filters. In a preferred embodiment, the cross sectional area of the grooves is greater than the cross sectional area of the axial flow passages. In a preferred embodiment, the cross-sectional area of the grooves ranges from about $2X10^{-4}$ in^2 to $5X10^{-2}$ in^2. In a preferred embodiment, the cross-sectional area of the axial flow passages ranges from about $2X10^{-4}$ in^2 to $5X10^{-2}$ in^2. In a preferred embodiment, the angle of attack of the first tapered end of the body ranges from about 10 to 30 degrees. In a preferred embodiment, the grooves are concentrated in a trailing edge portion of the tapered first end. In a preferred embodiment, the angle of inclination of the axial flow passages relative to the longitudinal axis of the expansion cone is greater than the angle of attack of the first tapered end. In a preferred embodiment, the grooves include a flow channel having a first radius of curvature, a first shoulder positioned on one side of the flow channel having a second radius of curvature, and a second shoulder positioned on the other side of the flow channel having a third radius of curvature. In a preferred embodiment, the first, second and third radii of curvature

are substantially equal. In a preferred embodiment, the the axial flow passages include a flow channel having a first radius of curvature, a first shoulder positioned on one side of the flow channel having a second radius of curvature, and a second shoulder positioned on the other side of the flow channel having a third radius of curvature. In a preferred embodiment, the first, second and third radii of curvature are substantially equal. In a preferred embodiment, the second radius of curvature is greater than the third radius of curvature.

A method of lubricating the interface between a tubular member and an expansion cone having a first tapered end and a second end during the radial expansion of the tubular member by the expansion cone, wherein the interface between the tubular member and the first tapered end of the expansion cone includes a leading edge portion and a trailing edge portion, has also been described that includes injecting a lubricating fluid into the trailing edge portion. In a preferred embodiment, the lubricating fluid has a viscosity ranging from about 1 to 10,000 centipoise. In a preferred embodiment, the injecting includes injecting lubricating fluid into the first tapered end of the expansion cone. In a preferred embodiment, the injecting includes injecting lubricating fluid into the area around the axial midpoint of the first tapered end of the expansion cone. In a preferred embodiment, the injecting includes injecting lubricating fluid into the second end of the expansion cone. In a preferred embodiment, the injecting includes injecting lubricating fluid into the tapered first end and the second end of the expansion cone. In a preferred embodiment, the injecting includes injecting lubricating fluid into the interior of the expansion cone. In a preferred embodiment, the injecting includes injecting lubricating fluid through the outer surface of the expansion cone. In a preferred embodiment, the injecting includes injecting the lubricating fluid into a plurality of discrete locations along the trailing edge portion. In a preferred embodiment, the lubricating fluid comprises drilling mud. In a preferred embodiment, the lubricating fluid further includes TorqTrim III, EP Mudlib, and DrillN-Slid. In a preferred

embodiment, the lubricating fluid comprises TorqTrim III, EP Mudlib, and DrillN-Slid.

A method of removing debris formed during the radial expansion of a tubular member by an expansion cone from the interface between the tubular member and the expansion cone, the expansion cone including a first tapered end and a second end, the interface between the tubular member and the first tapered end of the expansion cone includes a leading edge portion and a trailing edge portion, also has been described that includes injecting a lubricating fluid into the interface between the tubular member and the expansion cone. In a preferred embodiment, the lubricating fluid has a viscosity ranging from about 1 to 10,000 centipoise. In a preferred embodiment, the injecting includes injecting lubricating fluid into the first tapered end of the expansion cone. In a preferred embodiment, the injecting includes injecting lubricating fluid into the area around the axial midpoint of the first tapered end of the expansion cone. In a preferred embodiment, the injecting includes injecting lubricating fluid into the second end of the expansion cone. In a preferred embodiment, the injecting includes injecting lubricating fluid into the tapered first end and the second end of the expansion cone. In a preferred embodiment, the injecting includes injecting lubricating fluid into the interior of the expansion cone. In a preferred embodiment, the injecting includes injecting lubricating fluid through the outer surface of the expansion cone. In a preferred embodiment, the lubricating fluid comprises drilling mud. In a preferred embodiment, the lubricating fluid further includes TorqTrim III, EP Mudlib, and DrillN-Slid. In a preferred embodiment, the lubricating fluid comprises TorqTrim III, EP Mudlib, and DrillN-Slid.

A tubular member has also been described that includes an annular member having a wall thickness that varies less than about 8 %, a hoop yield strength that varies less than about 10 %, imperfections of less than about 8 % of the wall thickness, no failure for radial expansions of up to about 30 %, and no necking of the walls of the annular member for radial expansions of up to about 25%.

A wellbore casing has also been described that includes one or more tubular members. Each tubular member includes an annular member having a wall thickness that varies less than about 8 %, a hoop yield strength that varies less than about 10 %, imperfections of less than about 8 % of the wall thickness, no failure for radial expansions of up to about 30 %, and no necking of the walls of the annular member for radial expansions of up to about 25%.

A method of forming a wellbore casing also has been described that includes placing a tubular member and an expansion cone in a wellbore, and displacing the expansion cone relative to the tubular member. The tubular member includes an annular member having a wall thickness that varies less than about 8 %, a hoop yield strength that varies less than about 10 %, imperfections of less than about 8 % of the wall thickness, no failure for radial expansions of up to about 30 %, and no necking of the walls of the annular member for radial expansions of up to about 25%.

A method of selecting a group of tubular members for subsequent radial expansion also has been described that includes radially expanding the ends of a representative sample of the group of tubular members, measuring the amount of necking of the walls of the radially expanded ends of the tubular members, and if the radially expanded ends of the tubular members do not exhibit necking for radial expansions of up to about 25%, then accepting the group of tubular members.

A method of selecting a group of tubular members also has been described that includes radially expanding the ends of a representative sample of the group of tubular members until each of the tubular members fail, if the radially expanded ends of the tubular members do not fail for radial expansions of up to about 30%, then accepting the group of tubular members.

A method of inserting a tubular member into a wellbore also has been described that includes injecting a lubricating fluid into the wellbore, and inserting the tubular member into the wellbore. In a preferred embodiment, the thod of claim 774, wherein the lubricating fluid comprises BARO-LUB GOLD-SEAL™ brand drilling mud lubricant.

Although illustrative embodiments of the invention have been shown and described, a wide range of modification, changes and substitution is contemplated in the foregoing disclosure. In some instances, some features of the present invention may be employed without a corresponding use of the other features. Accordingly, it is appropriate that the appended claims be construed broadly and in a manner consistent with the scope of the invention.

Throughout this specification and the claims which follow, unless the context requires otherwise, the word "comprise", and variations such as "comprises" and "comprising", will be understood to imply the inclusion of a stated integer or step or group of integers or steps but not the exclusion of any other integer or step or group of integers or steps.

The reference to any prior art in this specification is not, and should not be taken as, an acknowledgment or any form of suggestion that that prior art forms part of the common general knowledge in Australia.

The Claims Defining The Invention Are As Follows:

1. An expansion cone for expanding a tubular member, comprising:
a housing including a tapered first end and a second end;
one or more grooves formed in an outer surface of the tapered first end and adapted to supply a lubricant to the outer surface; and
one or more axial flow passages fluidicly coupled to the grooves.

2. The expansion cone of claim 1, wherein the grooves comprise circumferential grooves.

3. The expansion cone of claim 1, wherein the grooves comprise spiral grooves.

4. The expansion cone of any one of claims 1 to 3, wherein the grooves are concentrated around the axial midpoint of the tapered portion of the housing.

5. The expansion cone of any one of claims 1 to 3, wherein the grooves are concentrated in a trailing edge portion of the tapered first end.

6. The expansion cone of any one of the preceding claims, wherein the axial flow passages comprise axial grooves.

7. The expansion cone of claim 6, wherein the axial grooves are spaced apart by at least about 3 inches (about 7.6 cm) in the circumferential direction.

8. The expansion cone of claim 6 or 7, wherein the axial grooves extend from the tapered first end of the housing to the one or more grooves formed in the outer surface of the tapered first end.

9. The expansion cone of claim 6 or 7, wherein the axial grooves extend from the second end of the housing to the one or more grooves formed in the outer surface

of the tapered first end.

10. The expansion cone of claim 6 or 7, wherein the axial grooves extend from the tapered first end of the housing to the second end of the housing.

11. The expansion cone of any one of claims 1 to 5, wherein the flow passages are positioned within the housing.

12. The expansion cone of claim 11, wherein the flow passages extend from the tapered first end of the housing to the grooves.

13. The expansion cone of claim 11, wherein the flow passages extend from the second end of the housing to the grooves.

14. The expansion cone of any one of claims 11 to 13, wherein the flow passages extend from the tapered first end of the housing to the second end of the housing.

15. The expansion cone of any one of claims 11 to 14, wherein one or more of the flow passages include inserts having restricted flow passages.

16. The expansion cone of any one of claims 11 to 15, wherein one or more of the flow passages include filters.

17. The expansion cone of any one of the preceding claims, wherein the cross sectional area of the grooves formed in the outer surface of the tapered first end is greater than the cross sectional area of the axial flow passages.

18. The expansion cone of any one of the preceding claims, wherein the cross-sectional area of the grooves formed in the outer surface of the tapered first end ranges from about $2x10^{-4}$ in^2 to $5x10^{-2}$ in^2 (about $13x10^{-4}cm^2$ to $32x10^{-2}cm^2$).

19. The expansion cone of any one of the preceding claims, wherein the cross-sectional area of the axial flow passages ranges from about $2x10^{-4}$ in^2 to $5x10^{-2}$ in^2 (about $13x10^{-4}cm^2$ to $32x10^{-2}cm^2$).

20. The expansion cone of any one of the preceding claims, wherein the angle of attack of the first tapered end of the housing ranges from about 10 to 30 degrees.

21. The expansion cone of any one of the preceding claims, wherein the angle of inclination of the axial flow passages relative to the longitudinal axis of the expansion cone is greater than the angle of attack of the first tapered end.

22. The expansion cone of any one of the preceding claims, wherein the grooves formed in the outer surface of the tapered first end include:

a flow channel having a first radius of curvature;

a first shoulder positioned on one side of the flow channel having a second radius of curvature; and

a second shoulder positioned on the other side of the flow channel having a third radius of curvature.

23. The expansion cone of claim 22, wherein the first, second and third radii of curvature are substantially equal.

24. The expansion cone of any one of the preceding claims, wherein the axial flow passages include:

a flow channel having a first radius of curvature;

a first shoulder positioned on one side of the flow channel having a second radius of curvature and;

a second shoulder positioned on the other side of the flow channel having a third radius of curvature.

25. The expansion cone of claim 24, wherein the first, second and third radii of

curvature are substantially equal.

26. The expansion cone of claim 22 or 24, wherein the second radius of curvature is greater than the third radius of curvature.

27. Apparatus, comprising:

a housing including a frustoconical portion and a cylindrical portion;

one or more grooves formed in the outer surface of the frustoconical portion and adapted to supply a lubricant to the outer surface; and

one or more axial flow passages formed in the housing fluidicly coupled to the grooves.

28. The apparatus of claim 27, wherein the grooves comprise circumferential grooves.

29. The apparatus of claim 27, wherein the grooves comprise spiral grooves.

30. The apparatus of any one of claims 27 to 29, wherein the grooves are concentrated around the axial midpoint of the frustoconical portion of the housing.

31. The apparatus of any one of claims 27 to 29, wherein the grooves are concentrated in a trailing edge portion of the frustoconical portion of the housing.

32. The apparatus of any one of claims 27 to 31, wherein the axial flow passages comprise axial grooves formed within the outer surface of the housing.

33. The apparatus of claim 32, wherein the axial grooves are spaced apart by at least about 3 inches (about 7.6 cm) in the circumferential direction.

34. The apparatus of claim 32 or 33, wherein the axial grooves are formed within the outer surface of the frustoconical portion of the housing.

35. The apparatus of claim 32 or 33, wherein the axial grooves are formed within the outer surface of the cylindrical portion of the housing.

36. The apparatus of claim 32 or 33, wherein the axial grooves are formed within the outer surface of the frustoconical and cylindrical portions of the housing.

37. The apparatus of any one of claims 27 to 31, wherein the flow passages are positioned within the housing.

38. The apparatus of claim 37, wherein the flow passages are positioned within the frustoconical portion of the housing.

39. The apparatus of claim 37, wherein the flow passages are positioned within the cylindrical portion of the housing.

40. The apparatus of claim 37, wherein the flow passages are positioned within the frustoconical and cylindrical portions of the housing.

41. The apparatus of any one of claims 37 to 40, wherein one or more of the flow passages include inserts having restricted flow passages.

42. The apparatus of any one of claims 37 to 41, wherein one or more of the flow passages include filters.

43. The apparatus of any one of claims 27 to 42, wherein the cross sectional area of the grooves formed in the outer surface of the frustoconical portion of the housing is greater than the cross sectional area of the axial flow passages.

44. The apparatus of any one of claims 27 to 43, wherein the cross-sectional area of the grooves formed in the outer surface of the frustoconical portion of the housing ranges from about $2x10^{-4}$ in^2 to $5x10^{-2}$ in^2 (about $13x10^{-4}cm^2$ to $32x10^{-2}cm^2$).

45. The apparatus of any one of claims 27 to 44, wherein the cross-sectional area of the axial flow passages ranges from about $2x10^{-4}$ in^2 to $5x10^{-2}$ in^2 (about $13x10^{-4}cm^2$ to $32x10^{-2}$ cm^2).

46. The apparatus of any one of claims 27 to 45, wherein the angle of attack of the frustoconical portion of the housing ranges from about 10 to 30 degrees.

47. The apparatus of any one of claims 27 to 46, wherein the angle of inclination of the axial flow passages relative to the longitudinal axis of the housing is greater than the angle of attack of the frustoconical portion of the housing.

48. The apparatus of any one of claims 27 to 47, wherein the grooves formed in the outer surface of the frustoconical portion of the housing include:

a flow channel having a first radius of curvature;

a first shoulder positioned on one side of the flow channel having a second radius of curvature; and

a second shoulder positioned on the other side of the flow channel having a third radius of curvature.

49. The apparatus of claim 48, wherein the first, second and third radii of curvature are substantially equal.

50. The apparatus of any one of claims 27 to 49, wherein the axial flow passages include:

a flow channel having a first radius of curvature;

a first shoulder positioned on one side of the flow channel having a second radius of curvature and;

a second shoulder positioned on the other side of the flow channel having a third radius of curvature.

51. The apparatus of claim 50, wherein the first, second and third radii of curvature are substantially equal.

52. The apparatus of claim 48 or 50, wherein the second radius of curvature is greater than the third radius of curvature.

53. The apparatus of any one of claims 27 to 52, further comprising:

a tubular member coupled to the outer surfaces of the frustoconical and cylindrical portions of the housing.

54. The apparatus of claim 53, wherein the tubular member comprises;

an annular member, including the properties of:

a wall thickness that varies less than about 8%;

a hoop yield strength that varies less than about 10%;

imperfections of less than about 8% of the wall thickness;

no failure for radial expansions of up to about 30%; and

no necking of the walls of the annular member for radial expansions of up to about 25%.

55. The apparatus of claim 53 or 54, wherein the tubular member comprises a wellbore casing.

56. The apparatus of claim 53 or 54, wherein the tubular member comprises a pipeline.

57. The apparatus of claim 53 or 54, wherein the tubular member comprises a structural support.

58. Apparatus for radially expanding a tubular member, comprising:

a tubular support member defining a first longitudinal passage extending therethrough;

an expansion cone coupled to the tubular support member comprising:

a housing including a tapered first end and a second end and defining a second longitudinal passage extending therethrough that is fluidicly coupled to the first longitudinal passage;

one or more grooves formed in the outer surface of the tapered first end and adapted to supply a lubricant to the outer surface; and

one or more axial flow passages fluidicly coupled to the grooves;

an expandable tubular member movably coupled to the tapered first end of the expansion cone; and

means for displacing the expansion cone relative to the expandable tubular member.

59. The apparatus of claim 58, wherein the grooves comprise circumferential grooves.

60. The apparatus of claim 58, wherein the grooves comprise spiral grooves.

61. The apparatus of any one of claims 58 to 60, wherein the grooves are concentrated around the axial midpoint of the tapered portion of the housing.

62. The apparatus of any one of claims 58 to 60, wherein the grooves are concentrated in a trailing edge portion of the tapered first end.

63. The apparatus of any one of claims 58 to 62, wherein the axial flow passages comprise axial grooves.

64. The apparatus of claim 63, wherein the axial grooves are spaced apart by at least about 3 inches (about 7.6 cm) in the circumferential direction.

65. The apparatus of claim 63 or 64, wherein the axial grooves extend from the tapered first end of the housing to the one or more grooves formed in the outer surface of the tapered first end.

66. The apparatus of claim 63 or 64, wherein the axial grooves extend from the second end of the housing to the one or more grooves formed in the outer surface of the tapered first end.

67. The apparatus of claim 63 or 64, wherein the axial grooves extend from the tapered first end of the housing to the second end of the housing.

68. The apparatus of any one of claims 58 to 62, wherein the flow passages are positioned within the housing of the expansion cone.

69. The apparatus of claim 68, wherein the flow passages extend from the tapered first end of the housing to the grooves.

70. The apparatus of claim 68, wherein the flow passages extend from the second end of the housing to the grooves.

71. The apparatus of any one of claims 68 to 70, wherein the flow passages extend from the tapered first end of the housing to the second end of the housing.

72. The apparatus of any one of claims 68 to 71, wherein one or more of the flow passages include inserts having restricted flow passages.

73. The apparatus of any one of claims 68 to 72, wherein one or more of the flow passages include filters.

74. The apparatus of any one of claims 58 to 73, wherein the cross sectional area of the grooves formed in the outer surface of the tapered first end is greater than the cross sectional area of the axial flow passages.

75. The apparatus of any one of claims 58 to 74, wherein the cross-sectional area of the grooves formed in the outer surface of the tapered first end ranges from about $2x10^{-4}$ in^2 to

$5x10^{-2}$ in^2 (about $13x10^{-4}cm^2$ to $32x10^{-2}cm^2$).

76. The apparatus of any one of claims 58 to 75, wherein the cross-sectional area of the axial flow passages ranges from about $2x10^{-4}$ in^2 to $5x10^{-2}$ in^2 (about $13x10^{-4}cm^2$ to $32x10^{-2}$ cm^2).

77. The apparatus of any one of claims 58 to 76, wherein the angle of attack of the first tapered end of the housing ranges from about 10 to 30 degrees.

78. The apparatus of any one of claims 58 to 77, wherein the angle of inclination of the axial flow passages relative to the longitudinal axis of the expansion cone is greater than the angle of attack of the first tapered end.

79. The apparatus of any one of claims 58 to 78, wherein the grooves formed in the outer surface of the tapered first end include:

a flow channel having a first radius of curvature;

a first shoulder positioned on one side of the flow channel having a second radius of curvature; and

a second shoulder positioned on the other side of the flow channel having a third radius of curvature.

80. The apparatus of claim 79, wherein the first, second and third radii of curvature are substantially equal.

81. The apparatus of any one of claims 58 to 80, wherein the axial flow passages include:

a flow channel having a first radius of curvature;

a first shoulder positioned on one side of the flow channel having a second radius of curvature and;

a second shoulder positioned on the other side of the flow channel having a third radius of curvature.

82. The apparatus of claim 81, wherein the first, second and third radii of curvature are substantially equal.

83. The apparatus of claim 79 or 81, wherein the second radius of curvature is greater than the third radius of curvature.

84. An expansion cone substantially as hereinbefore described with reference to the accompanying drawings.

85. The apparatus of claim 27 substantially as hereinbefore described with reference to the accompanying drawings.

86. The apparatus of claim 58 substantially as hereinbefore described with reference to the accompanying drawings.

Dated this 23rd day of March 2004

Shell Internationale Research Maatschappij B.V.

By Its Patent Attorneys

DAVIES COLLISON CAVE

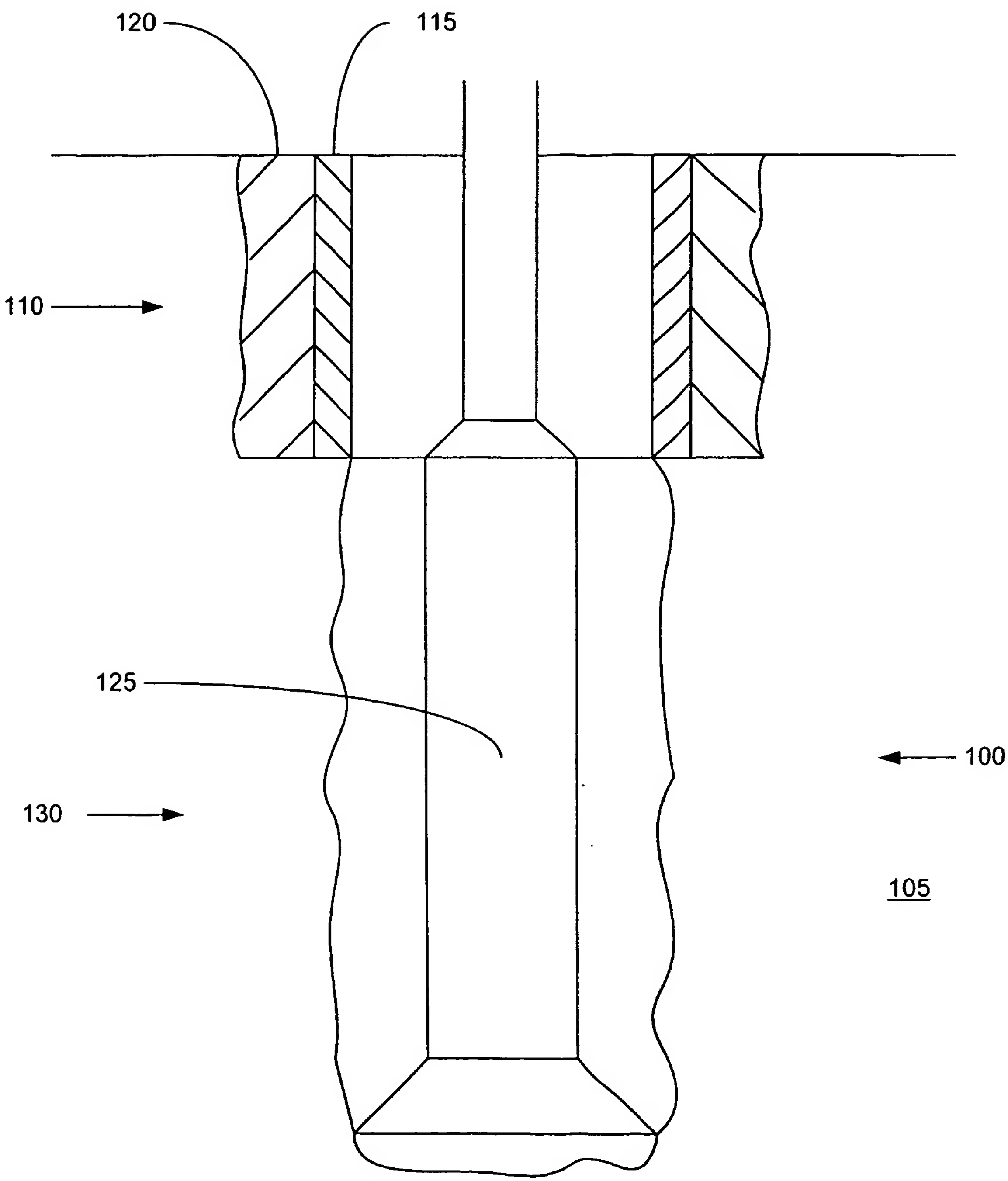

FIGURE 1

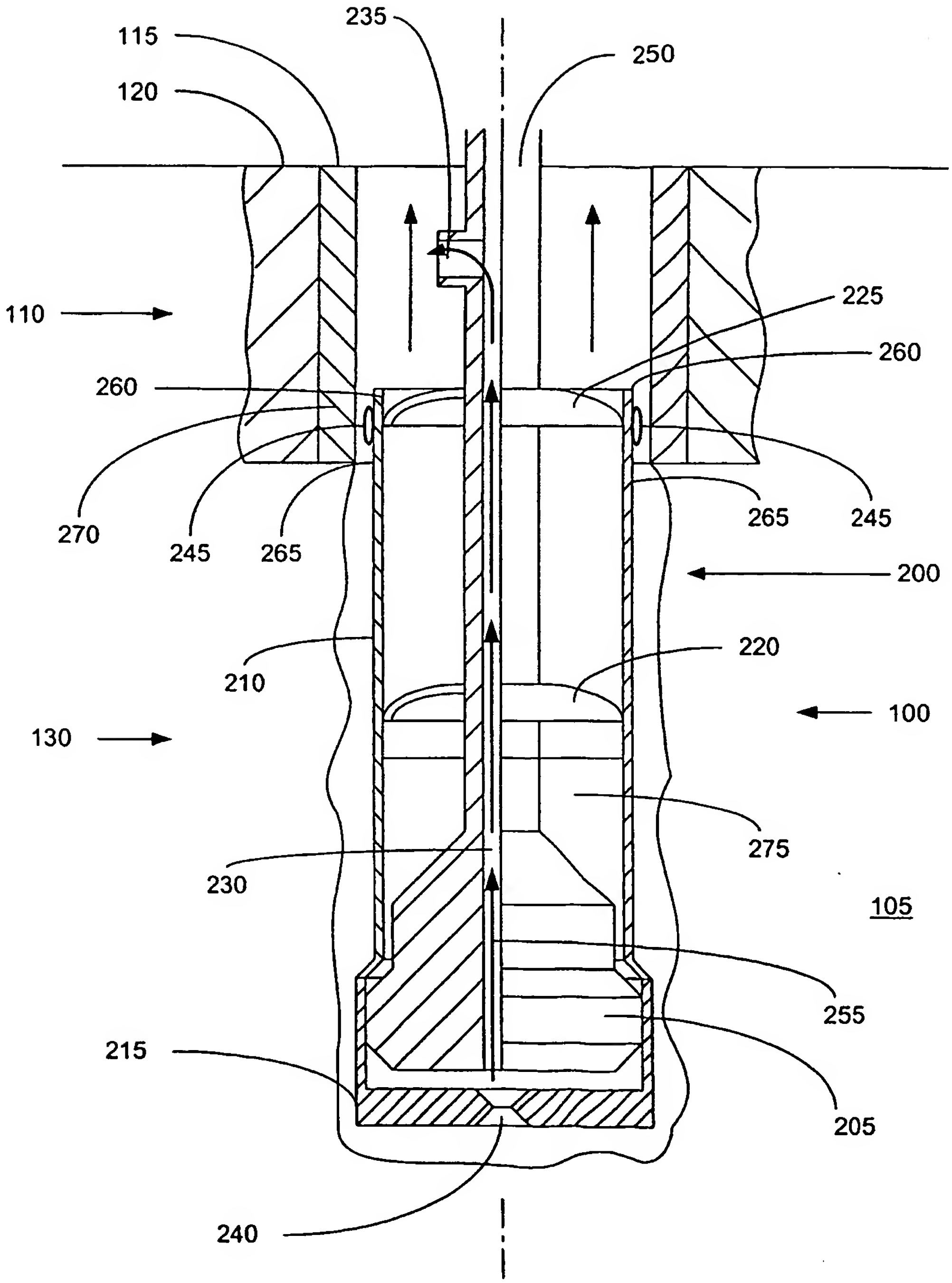
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FIGURE 2

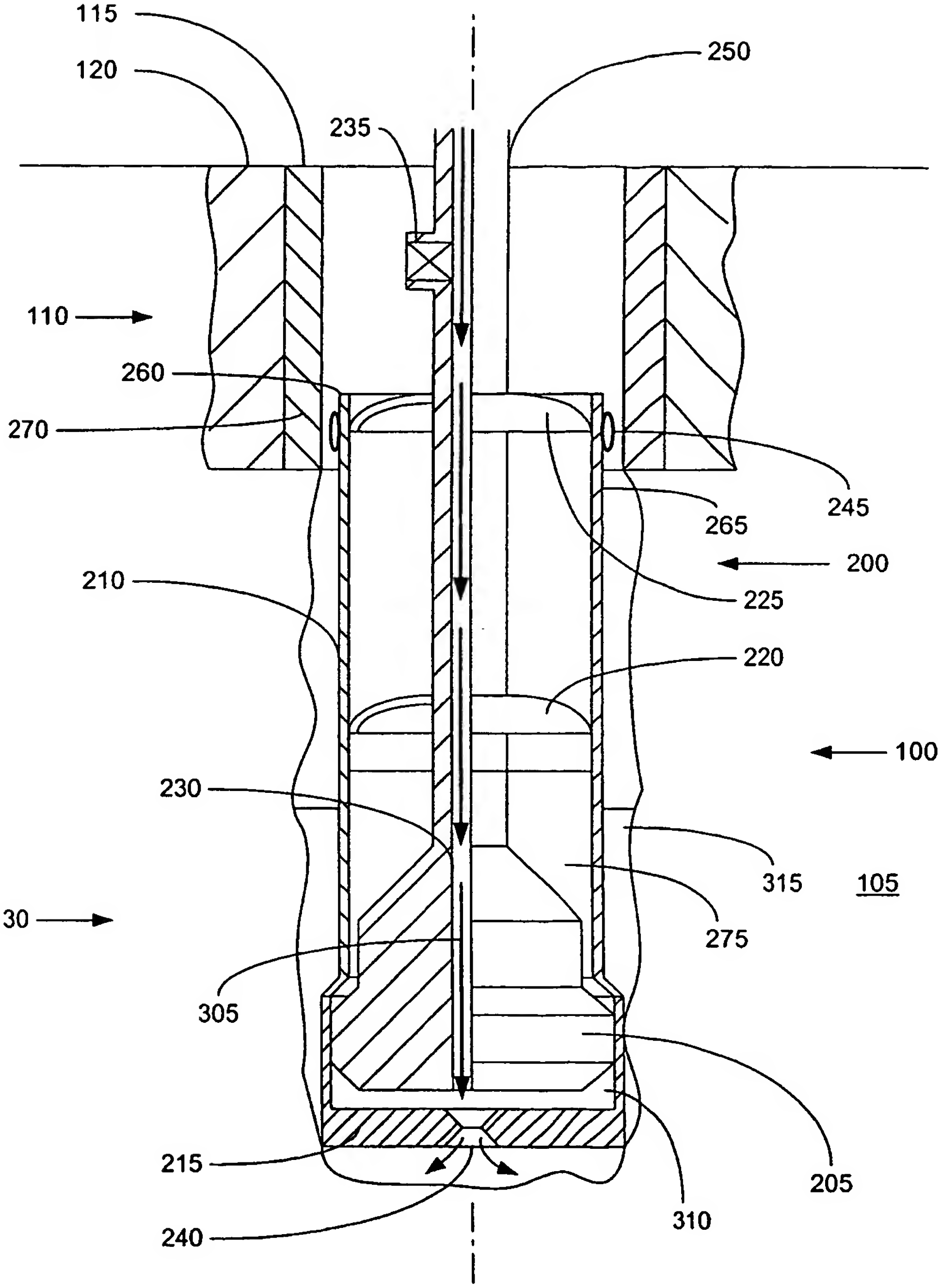
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FIGURE 3

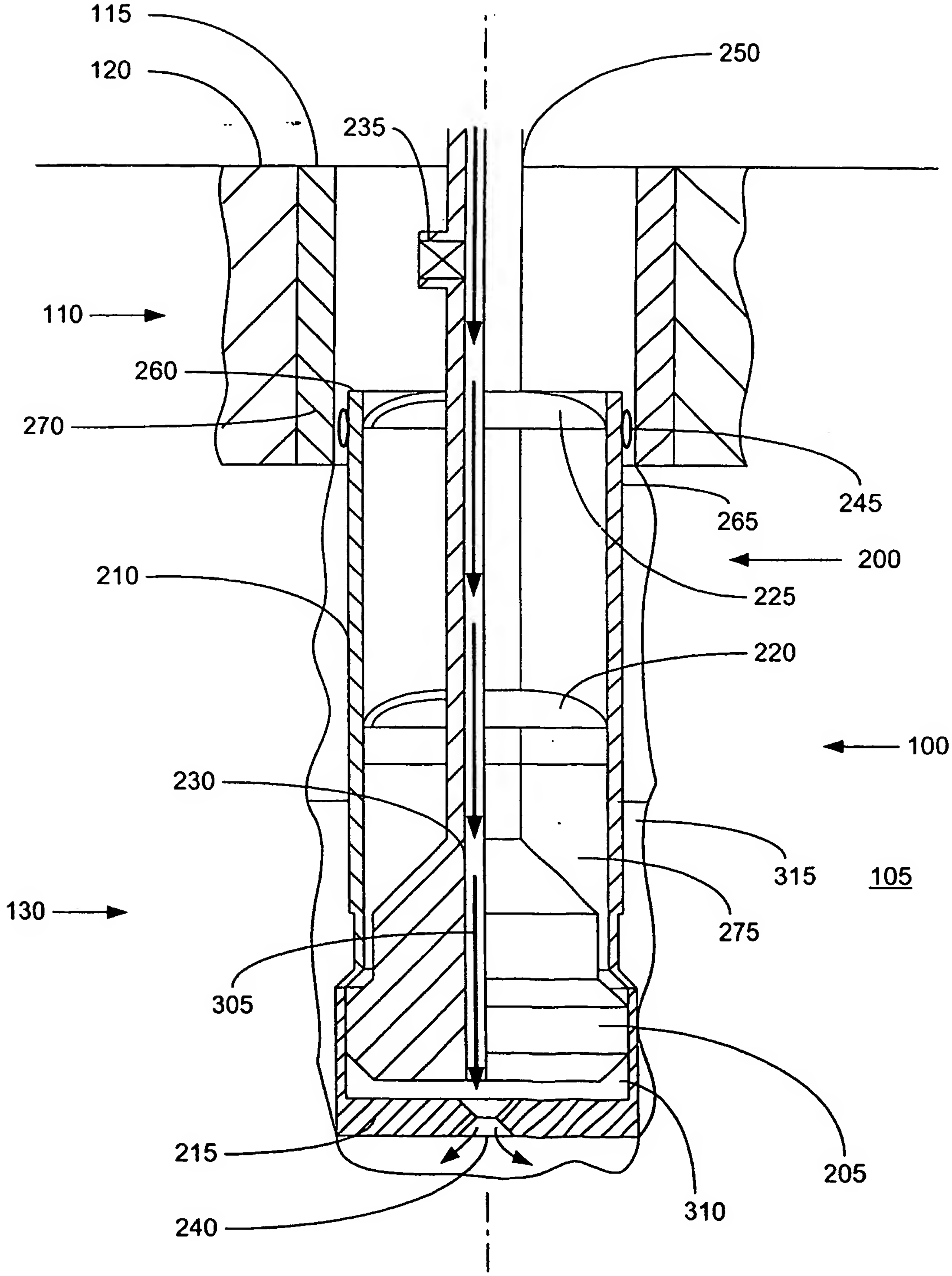
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FIGURE 3a

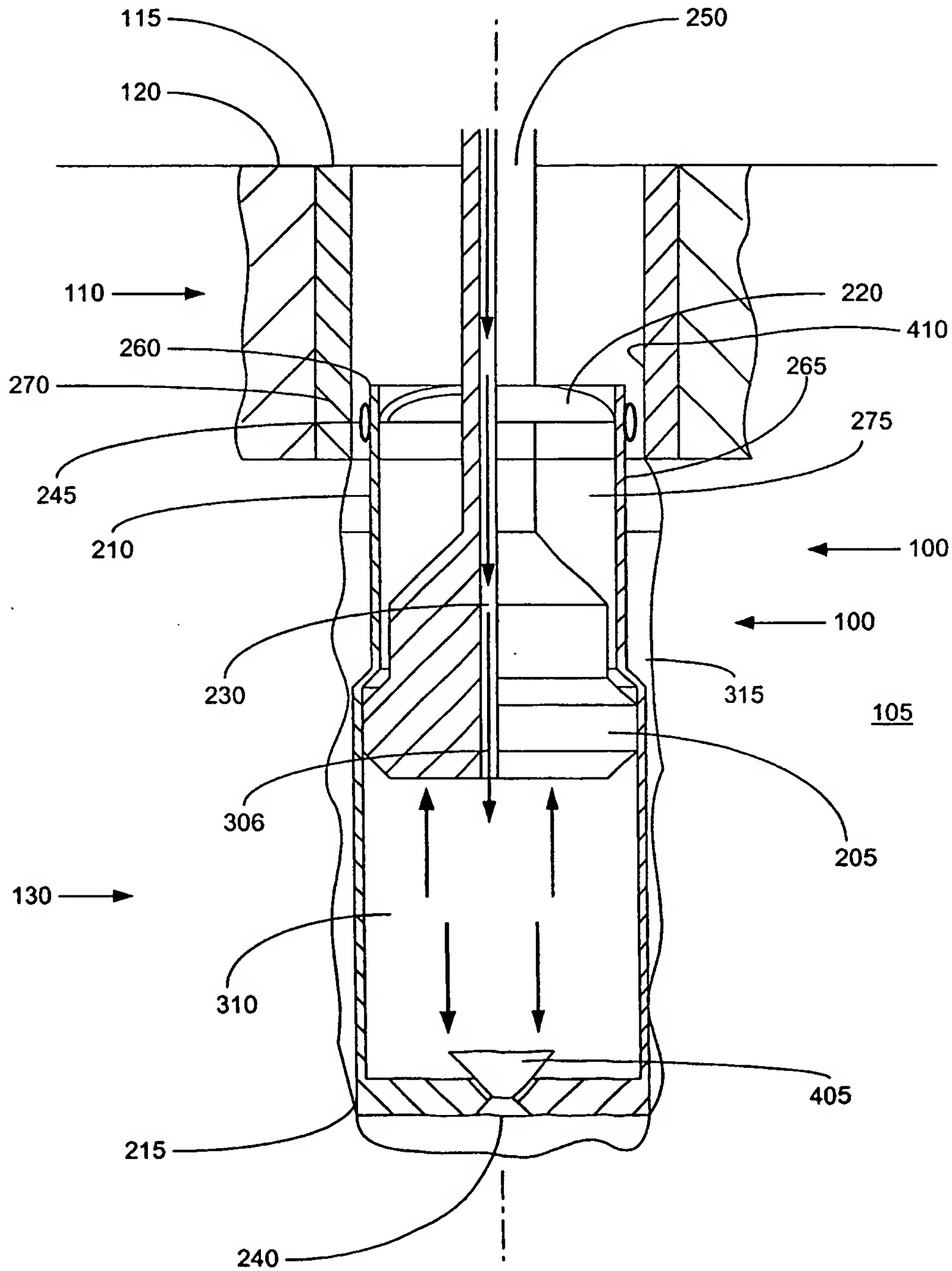
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FIGURE 4

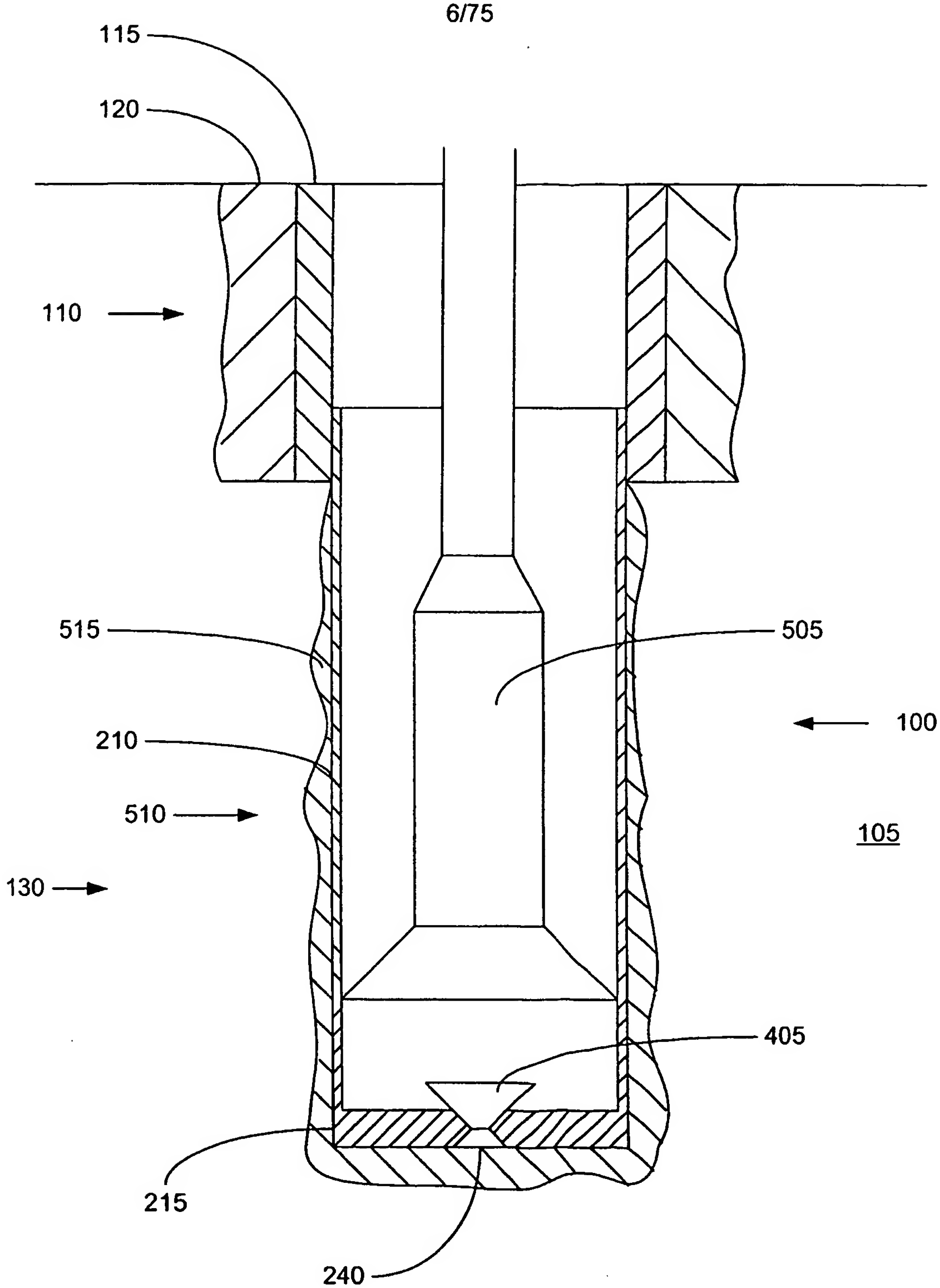

FIGURE 5

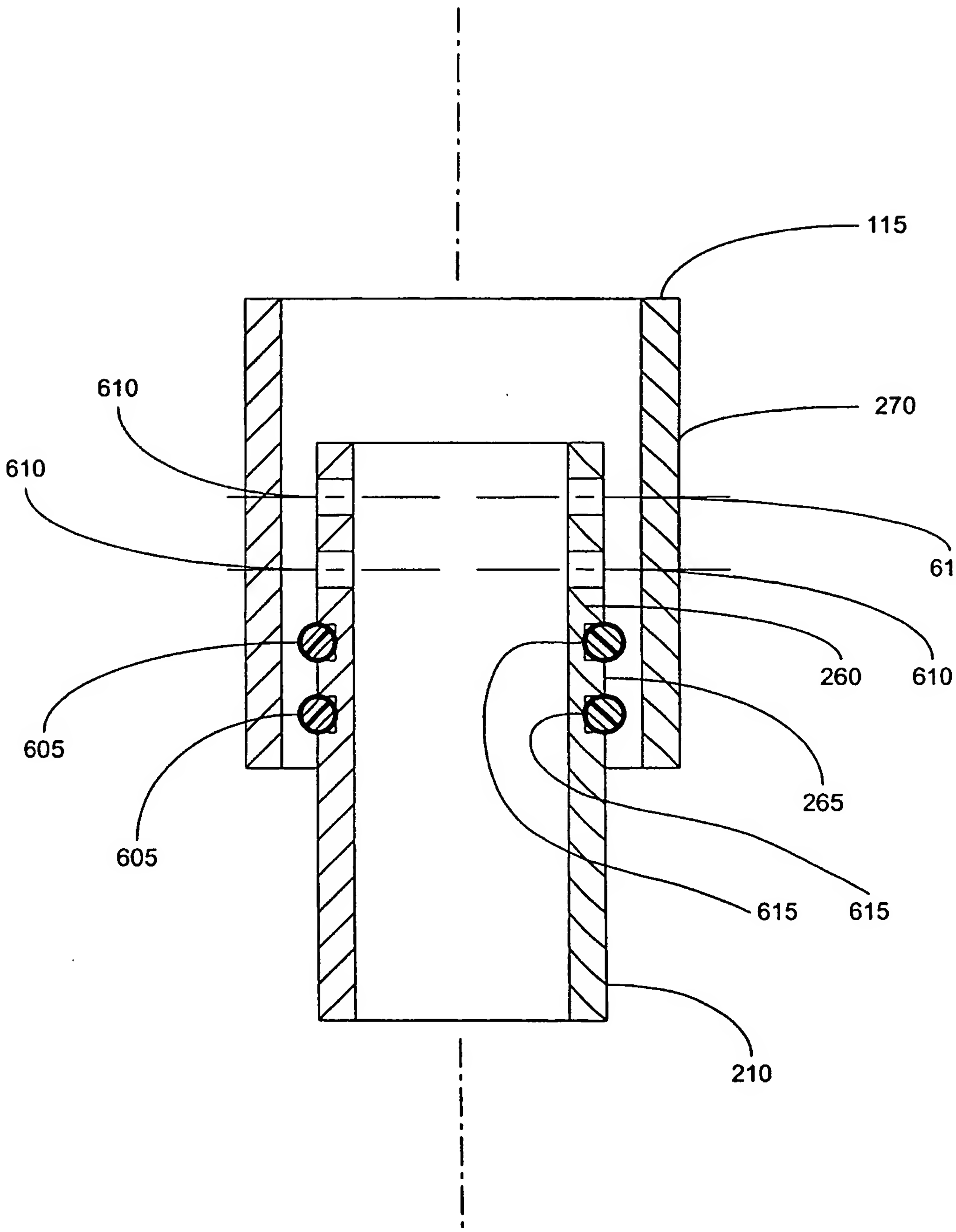

FIGURE 6

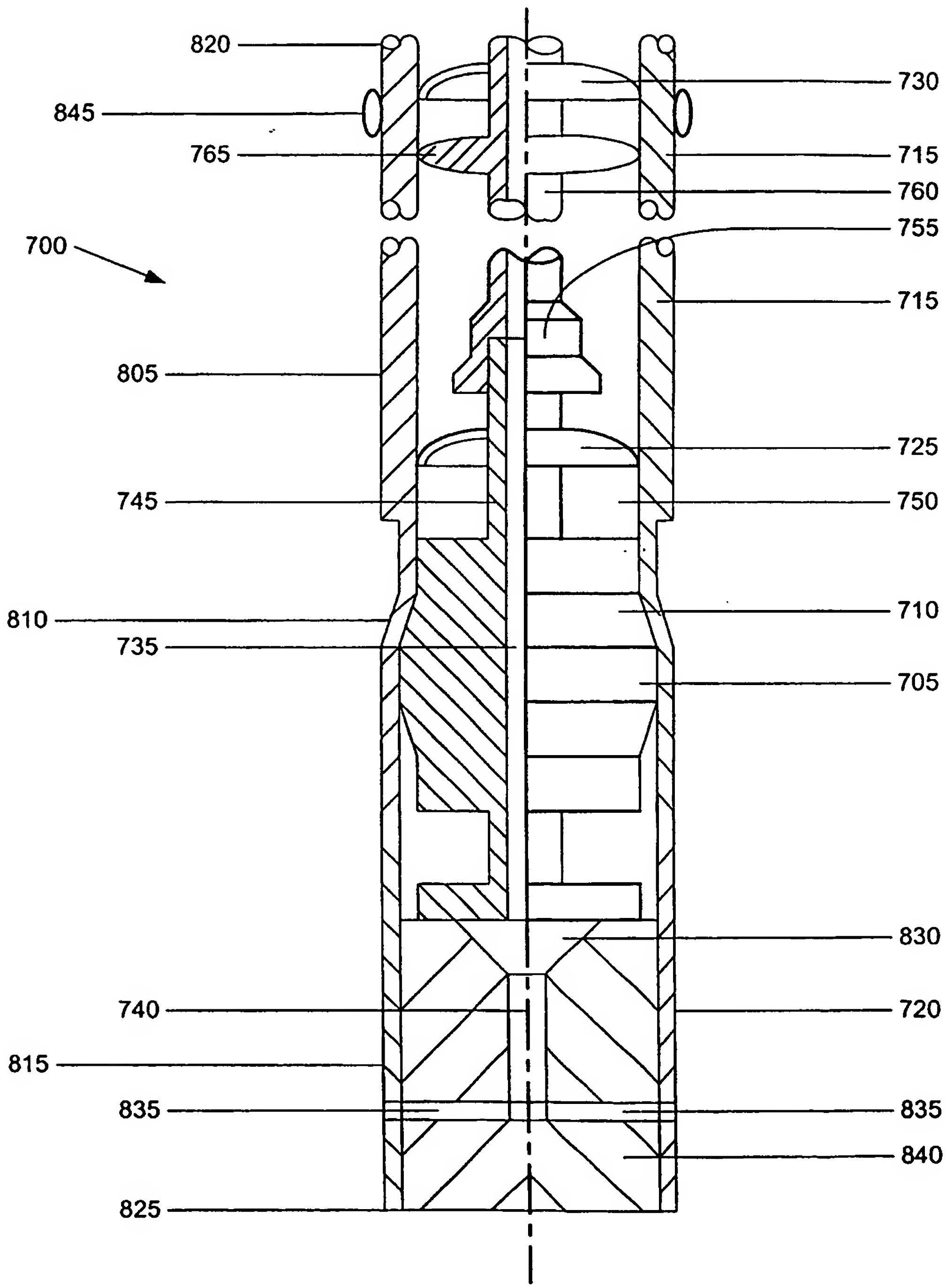
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FIGURE 7

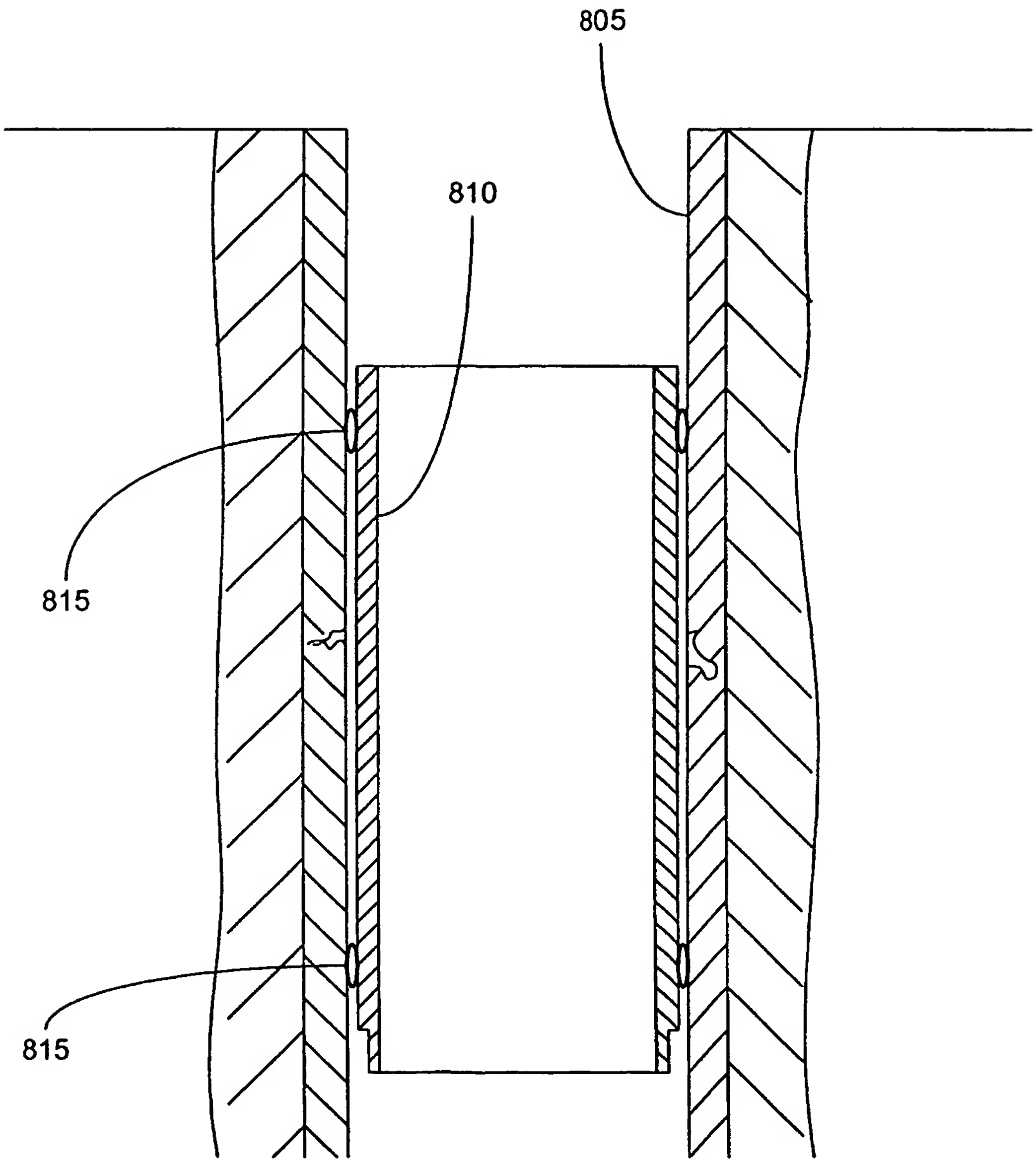

FIGURE 8

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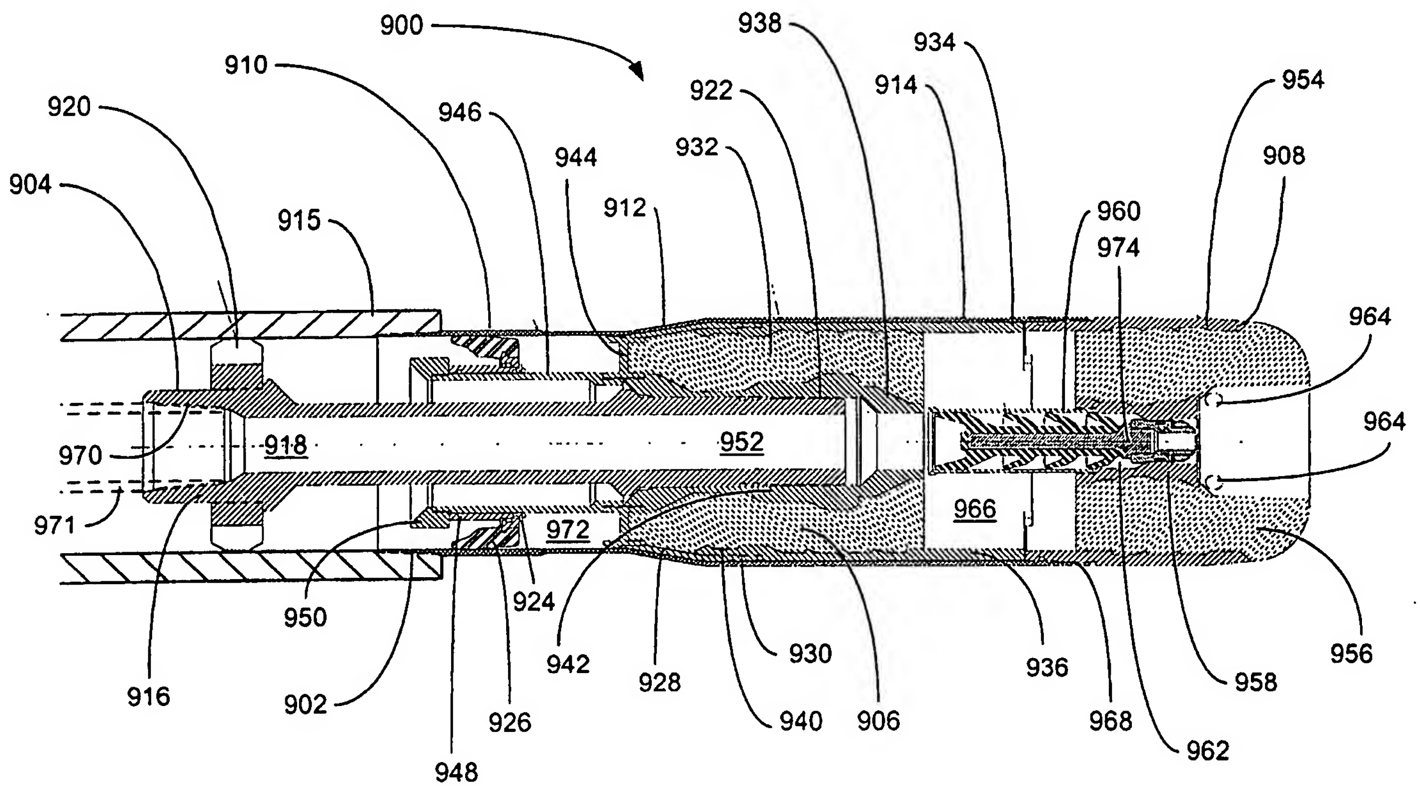

FIGURE 9

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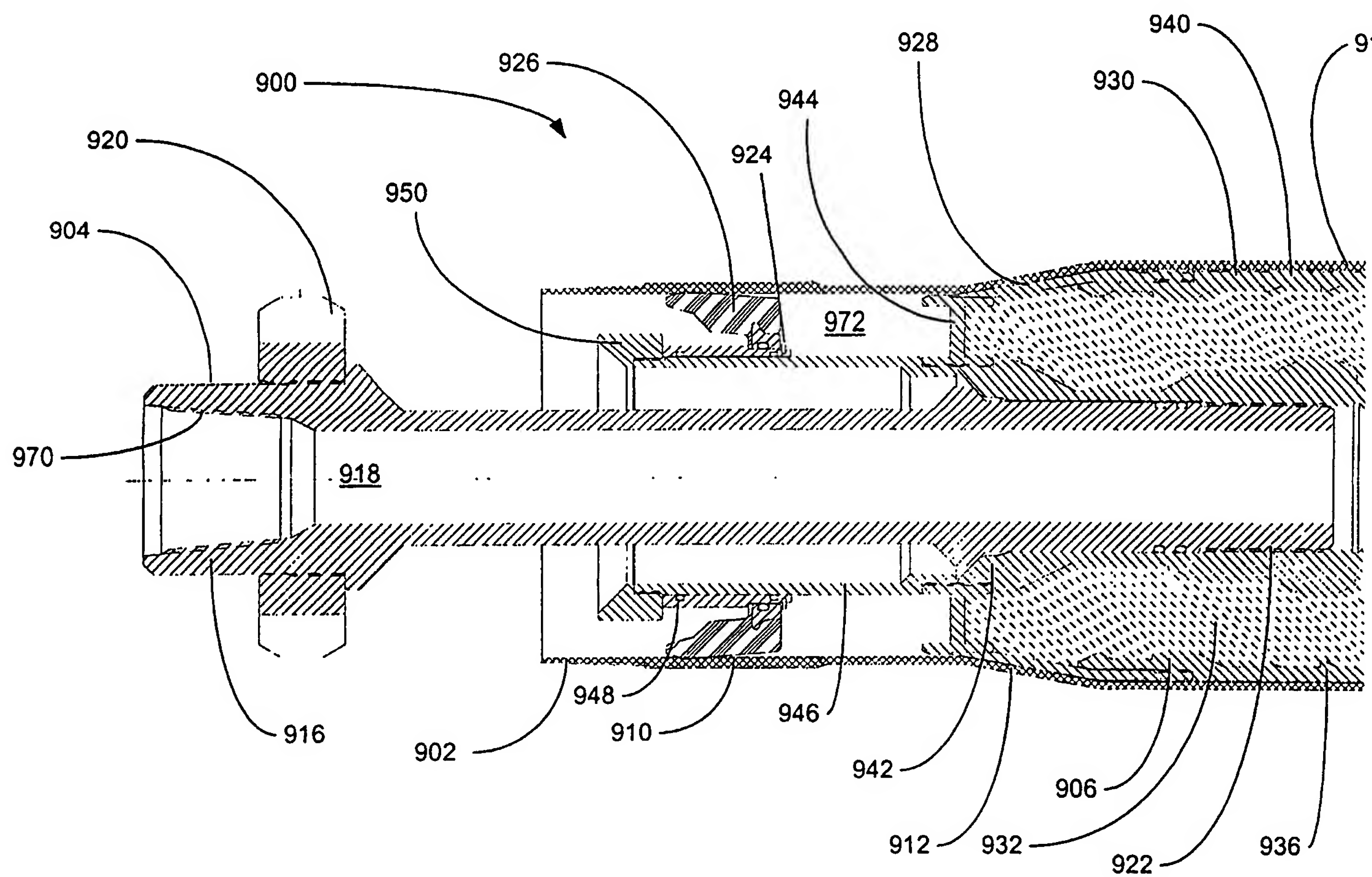

FIGURE 9a

23 11 00 T1777

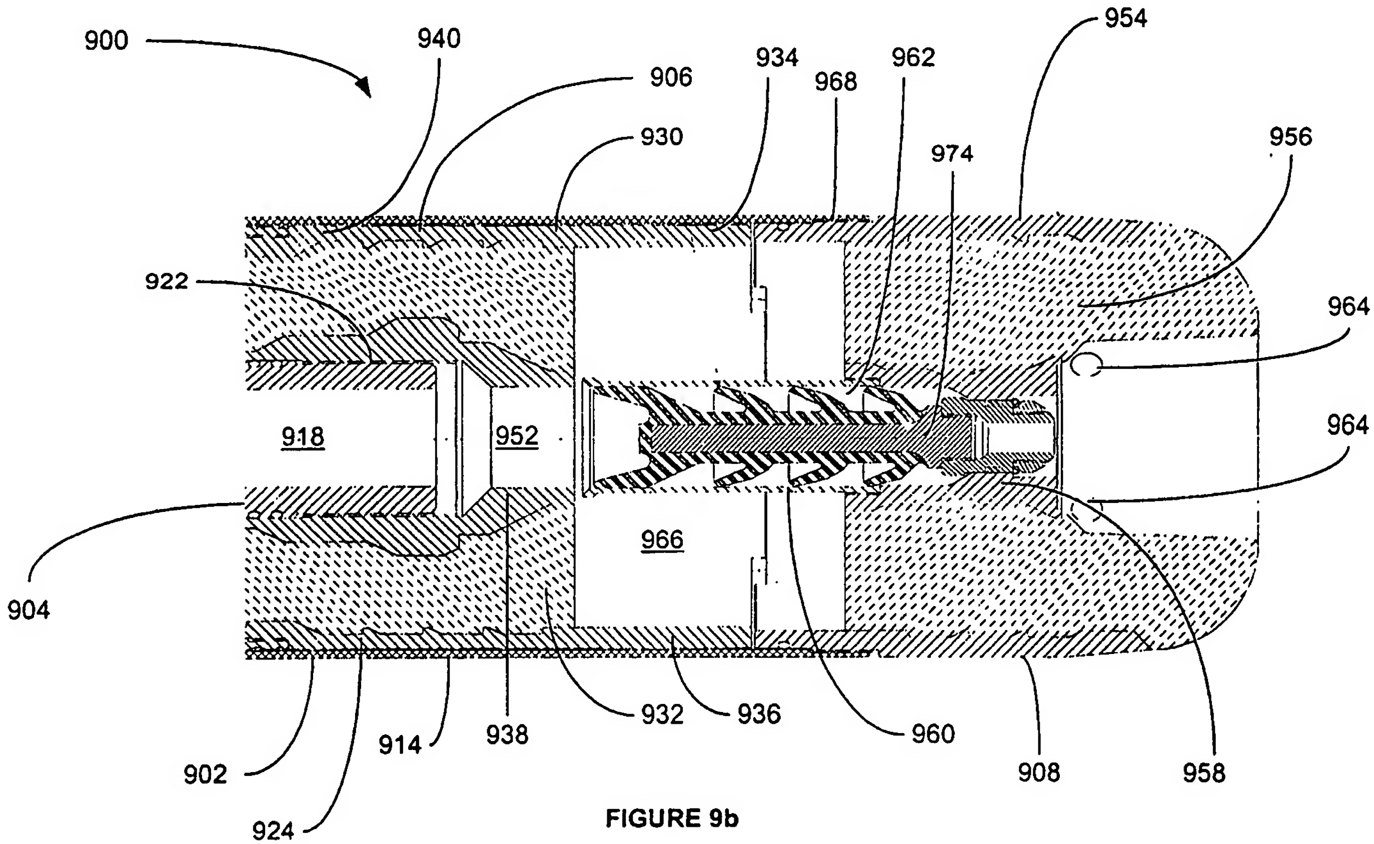

FIGURE 9b

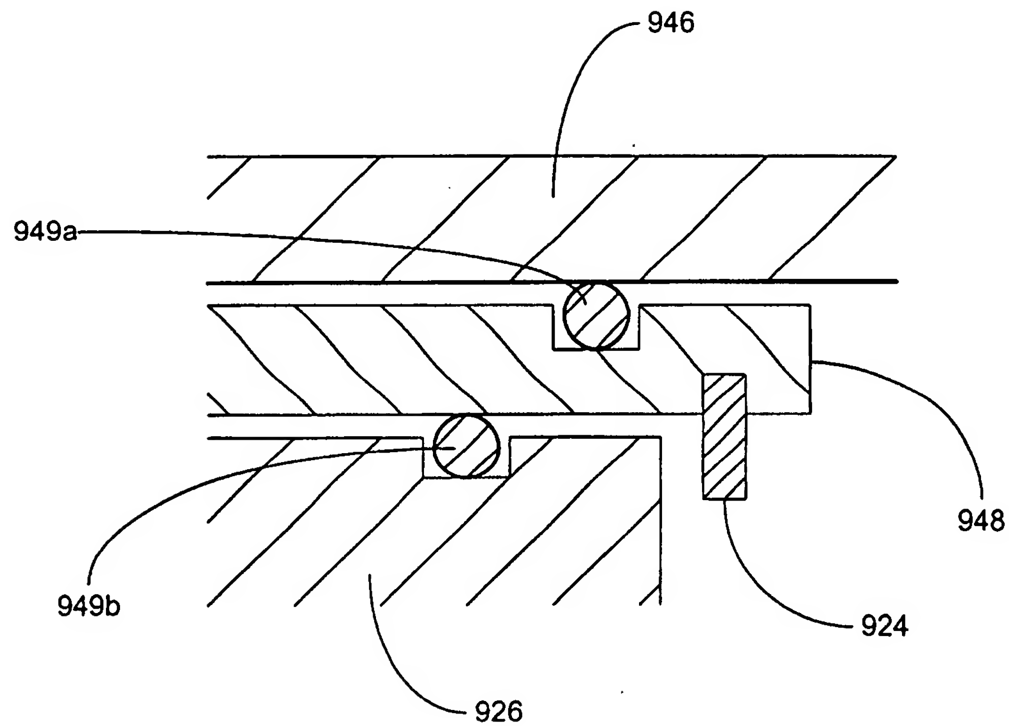

FIGURE 9C

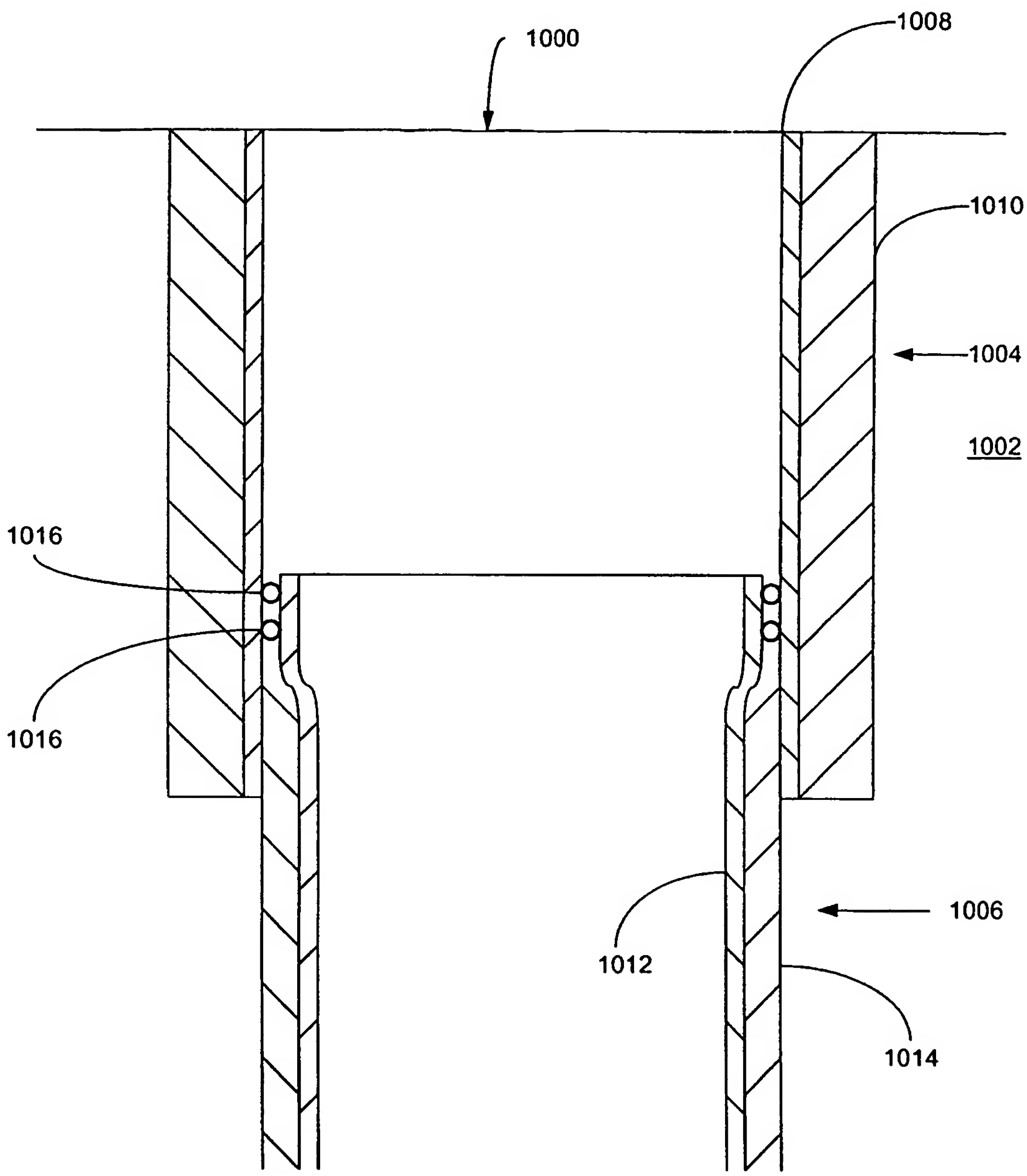

FIGURE 10a

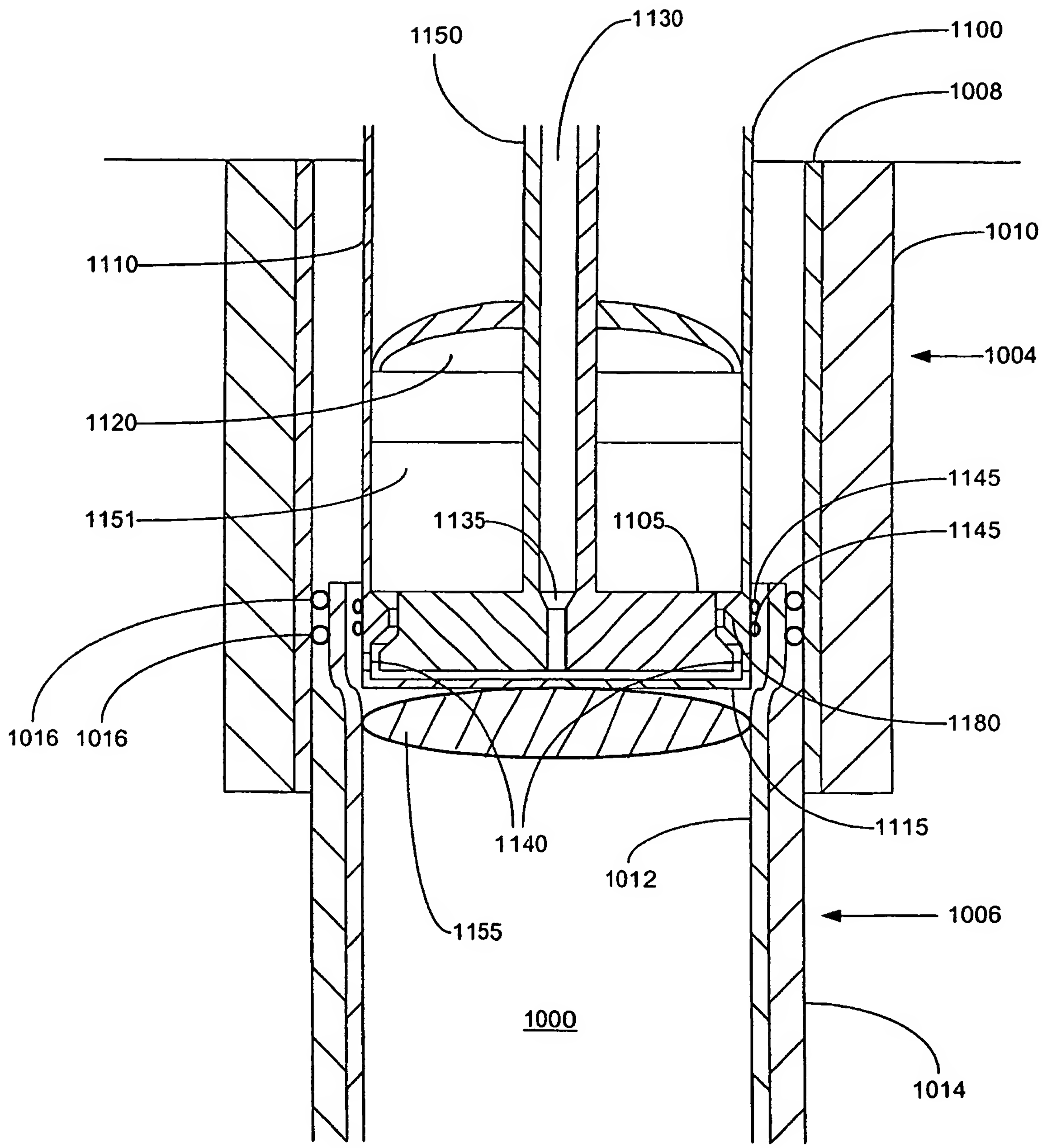
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FIGURE 10b

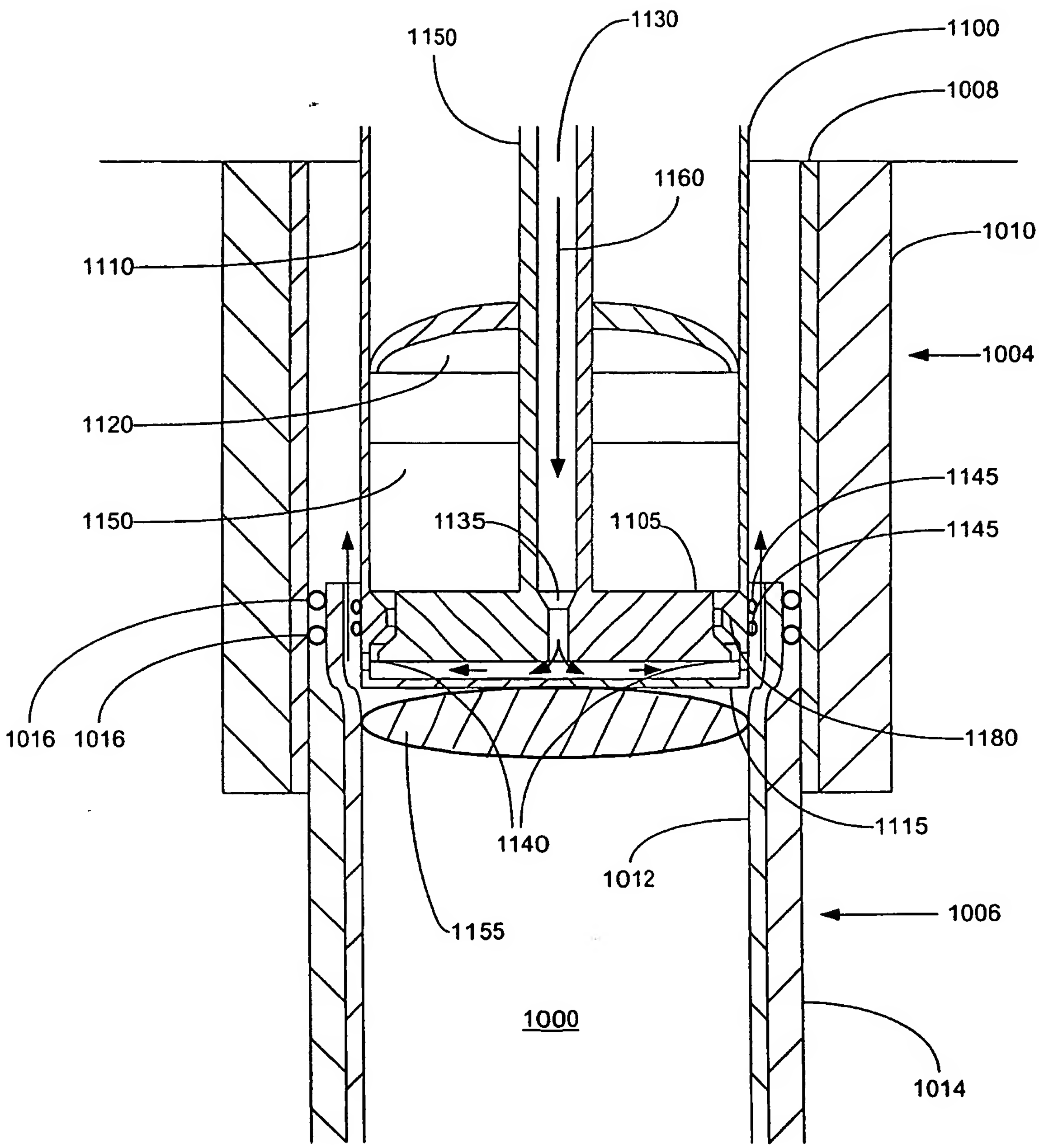
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FIGURE 10c

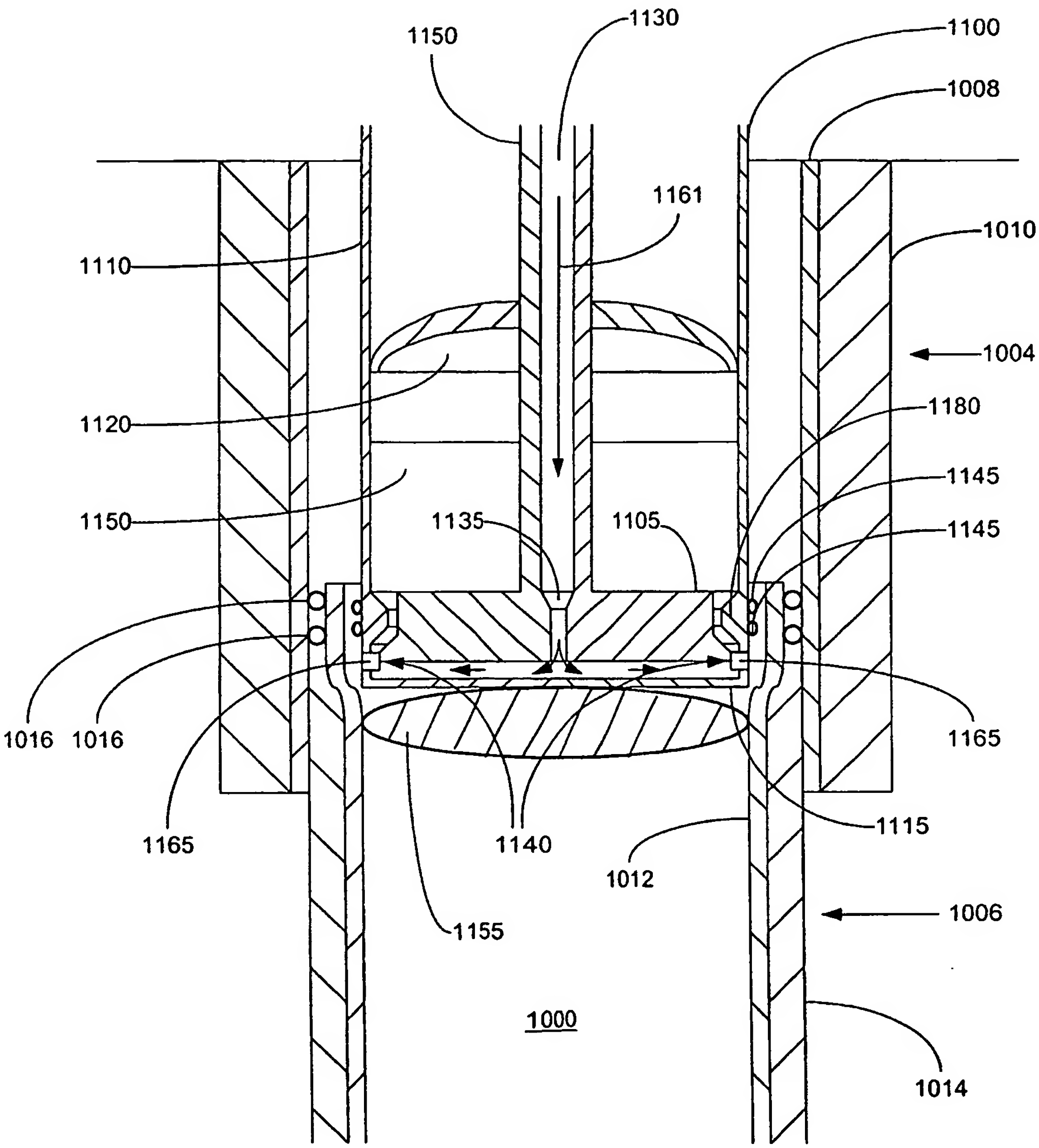

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FIGURE 10d

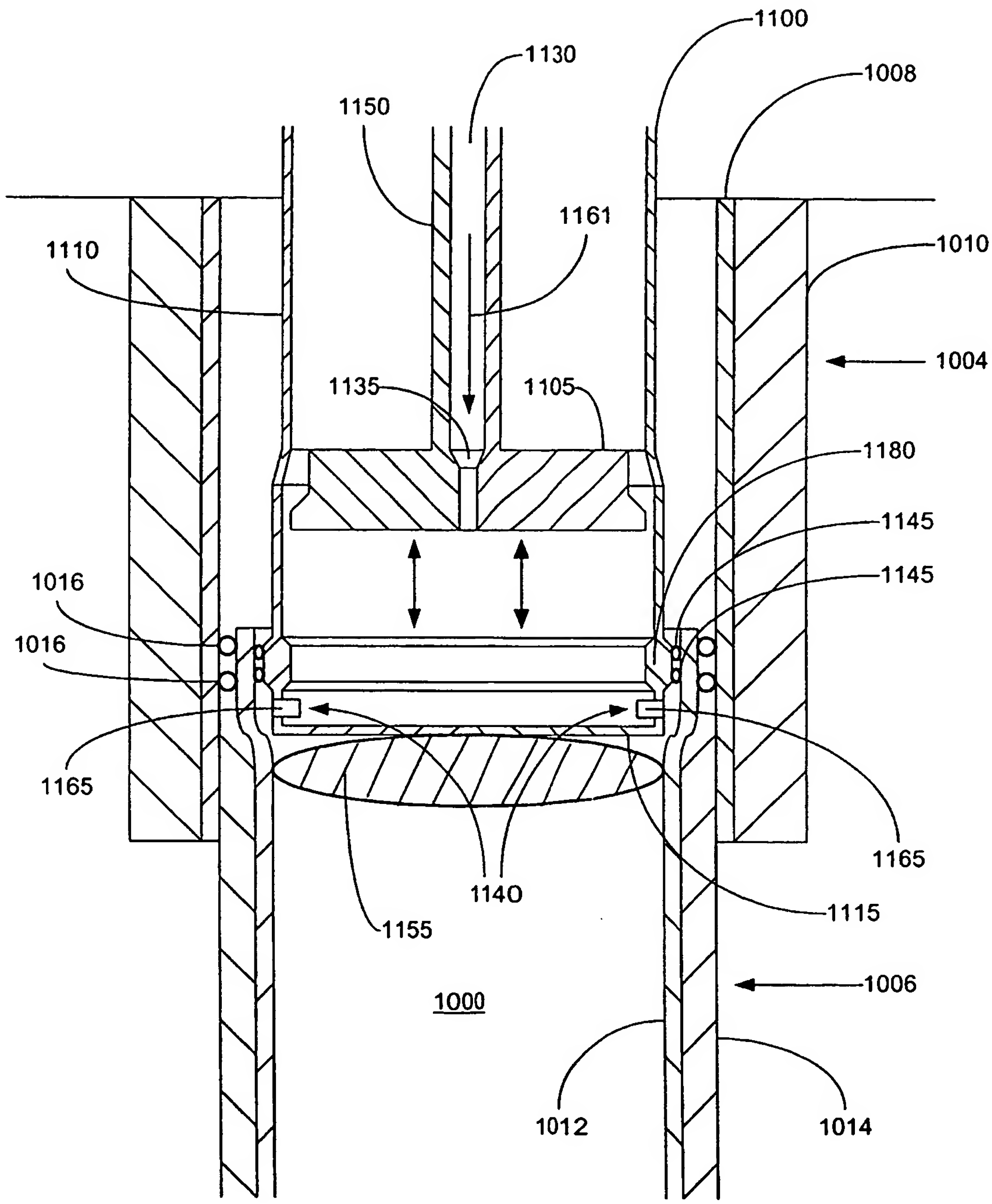
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FIGURE 10e

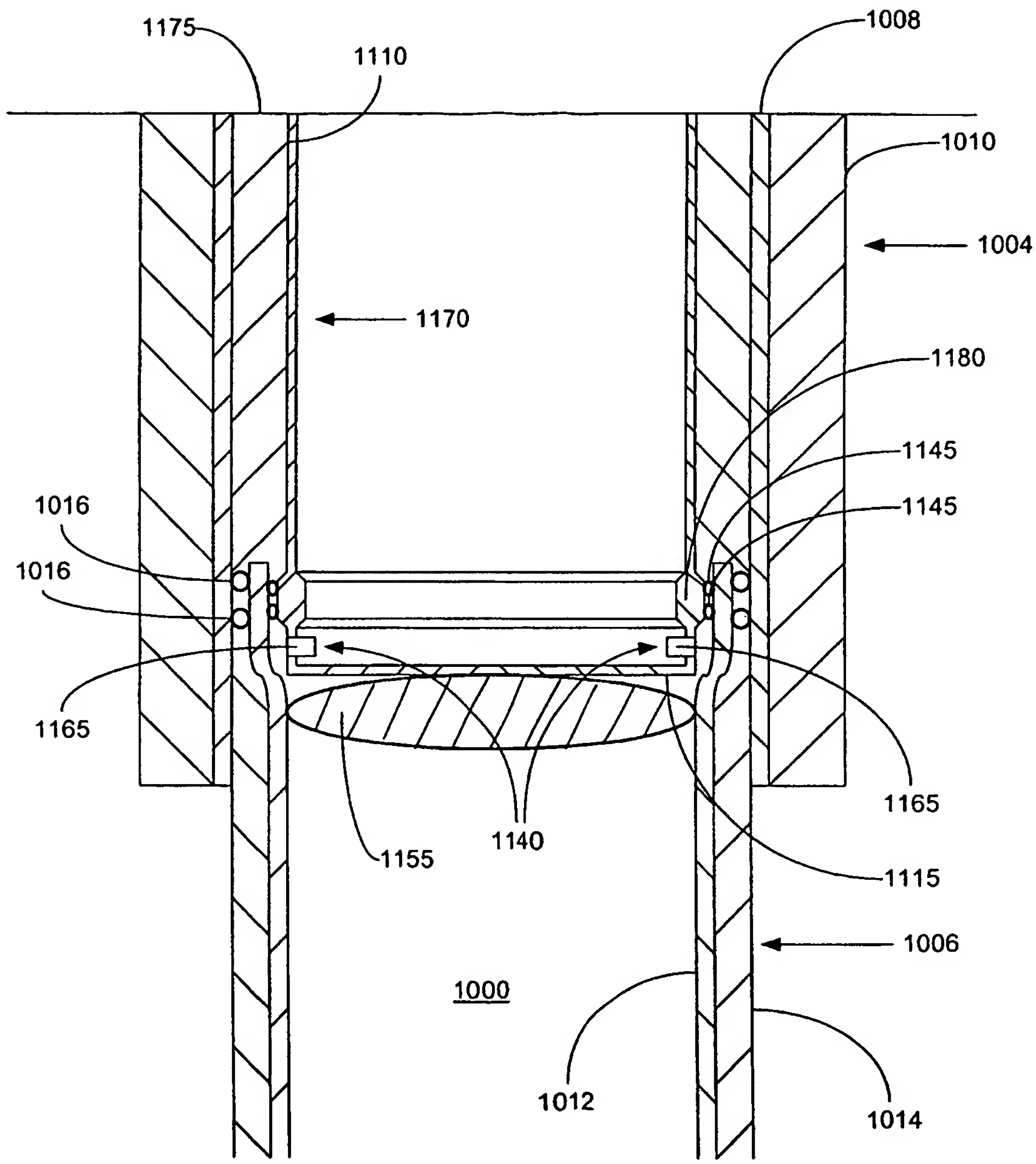
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FIGURE 10f

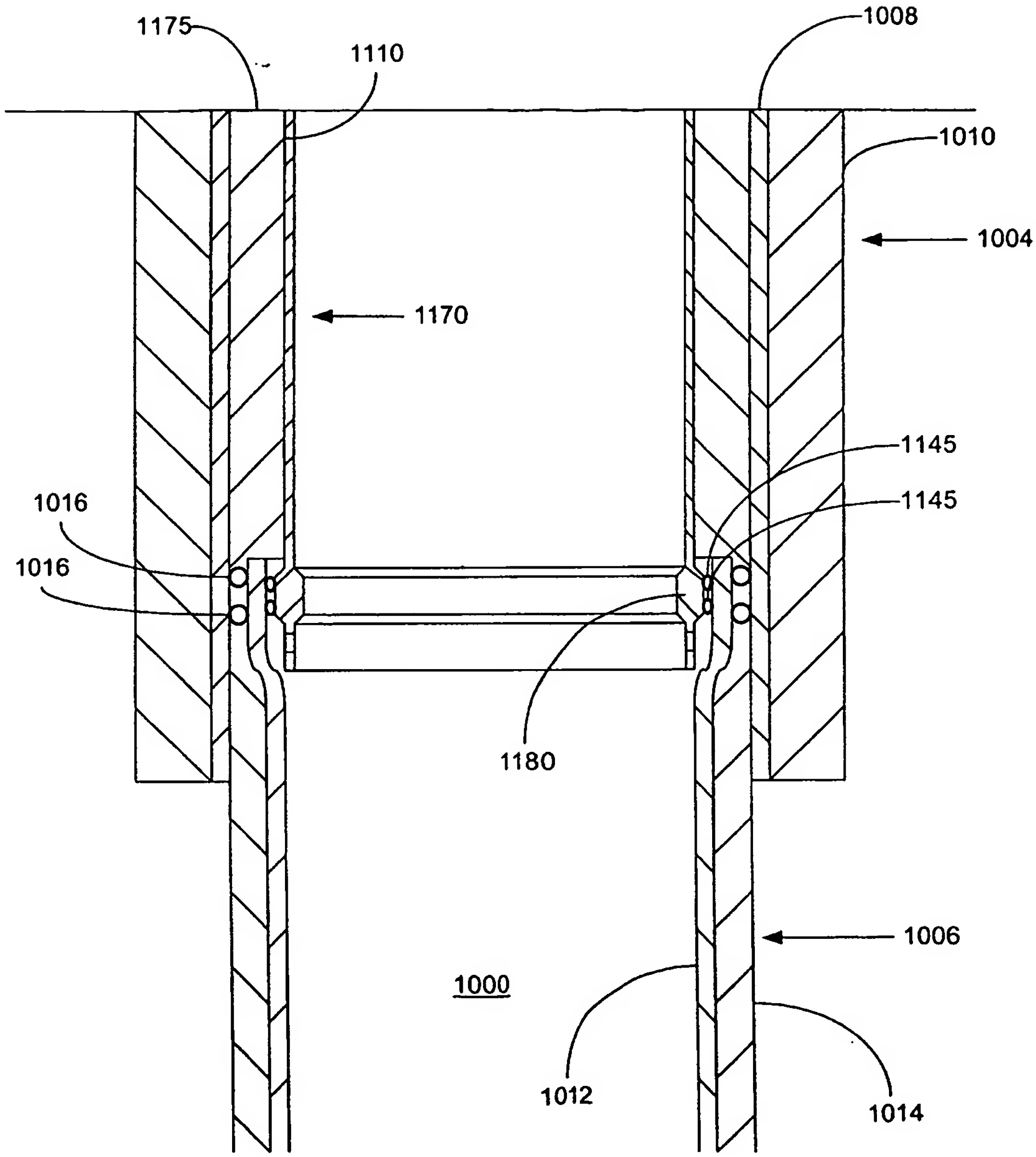
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FIGURE 10g

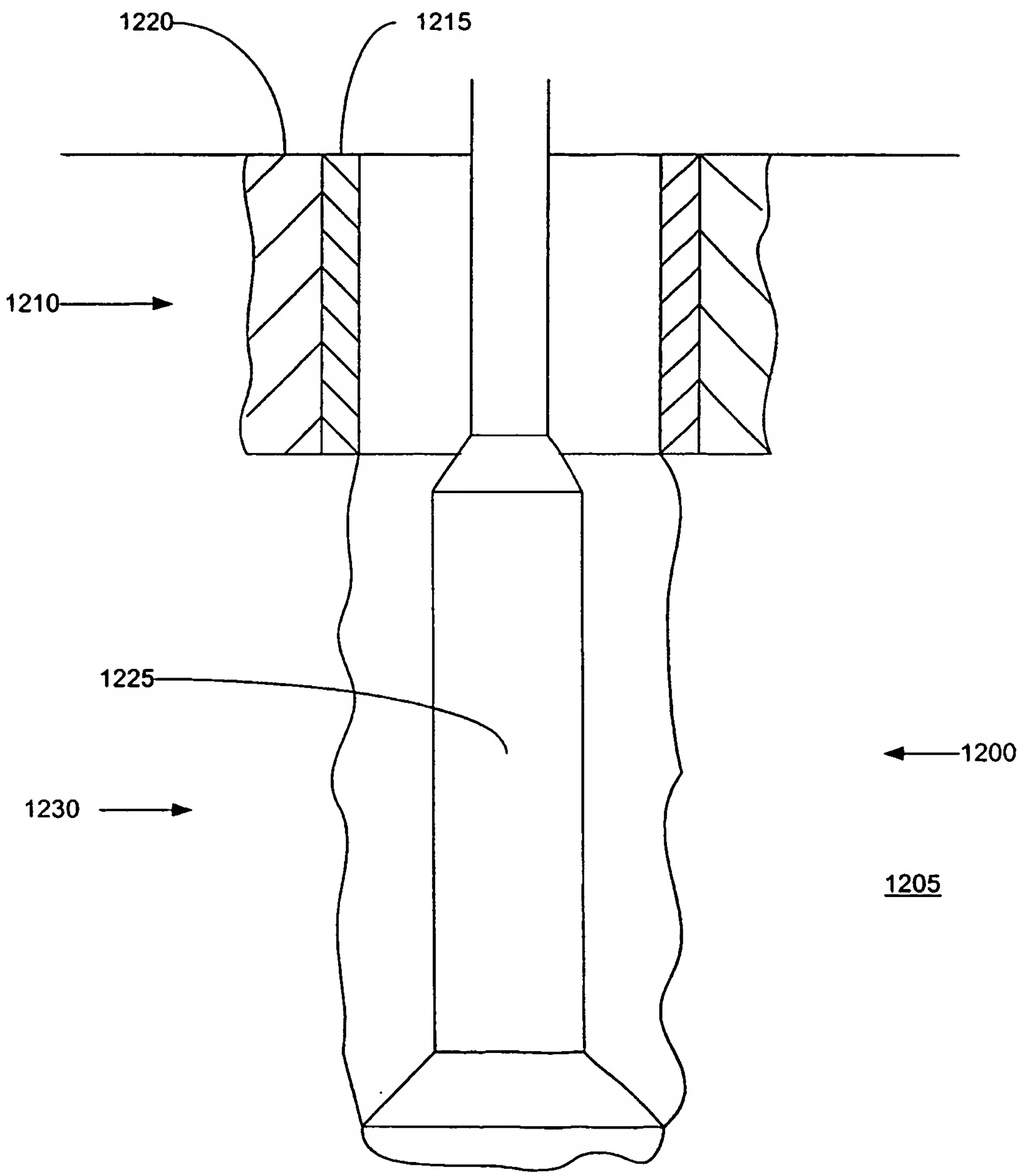

FIGURE 11a

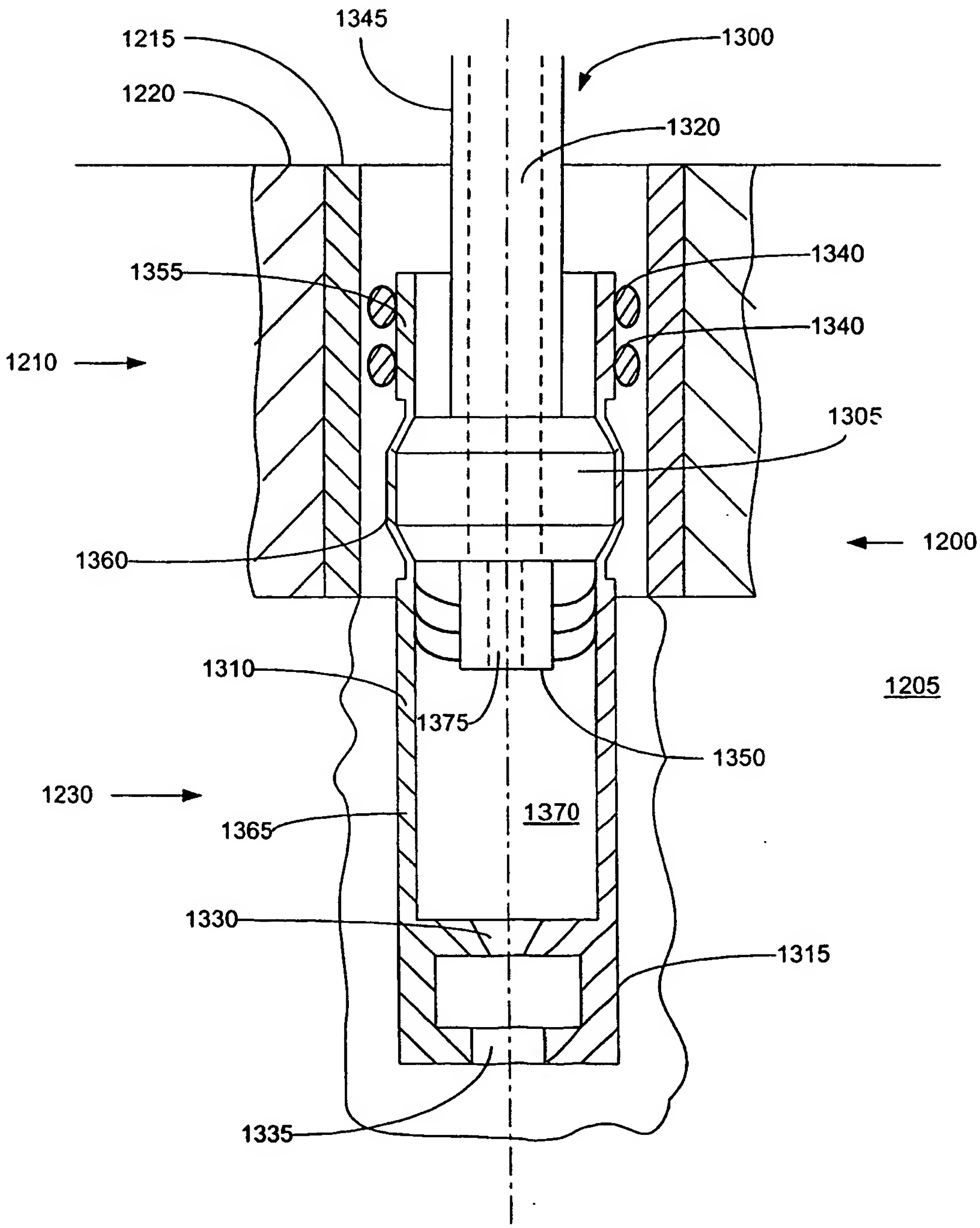
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FIGURE 11b

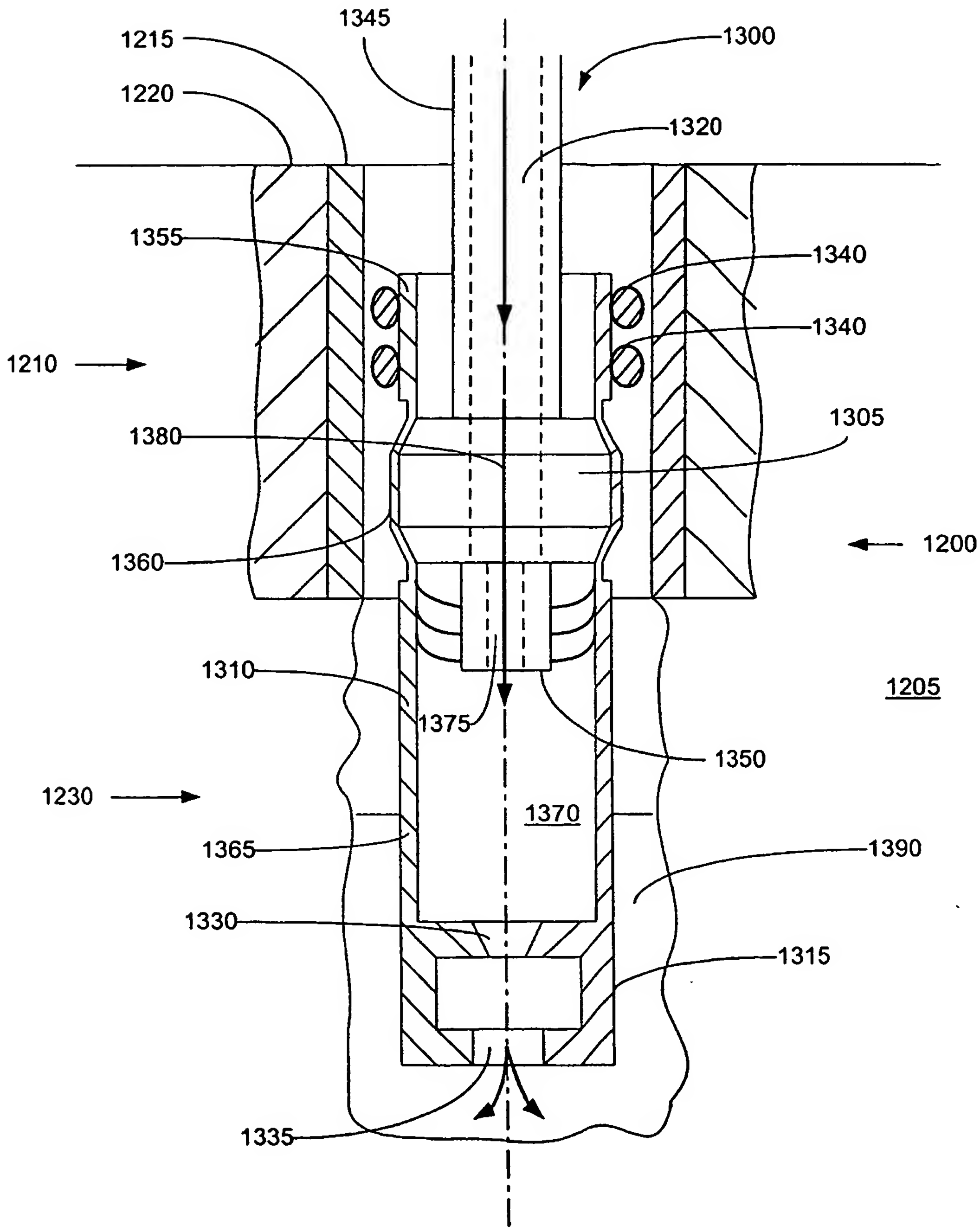
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FIGURE 11c

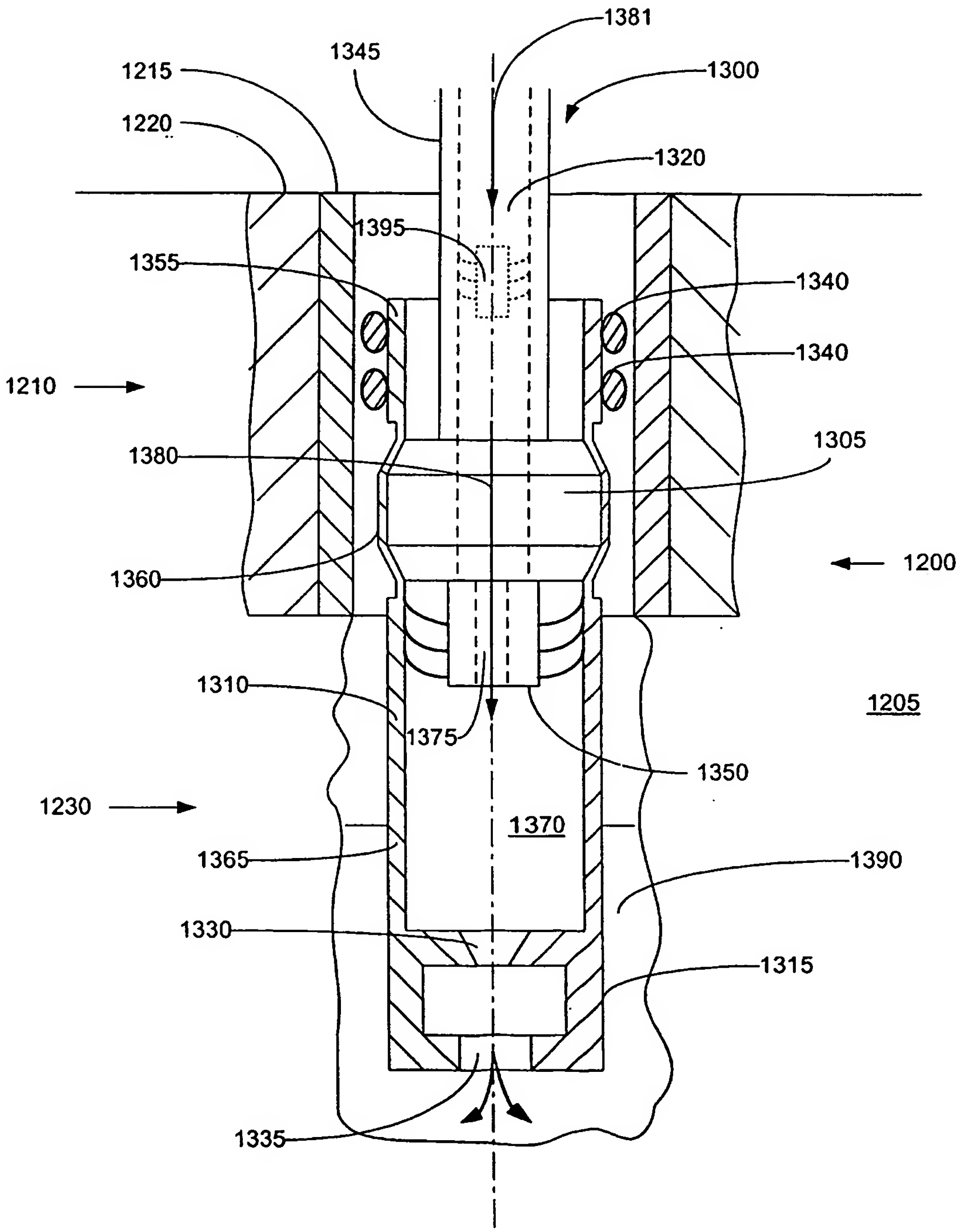
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FIGURE 11d

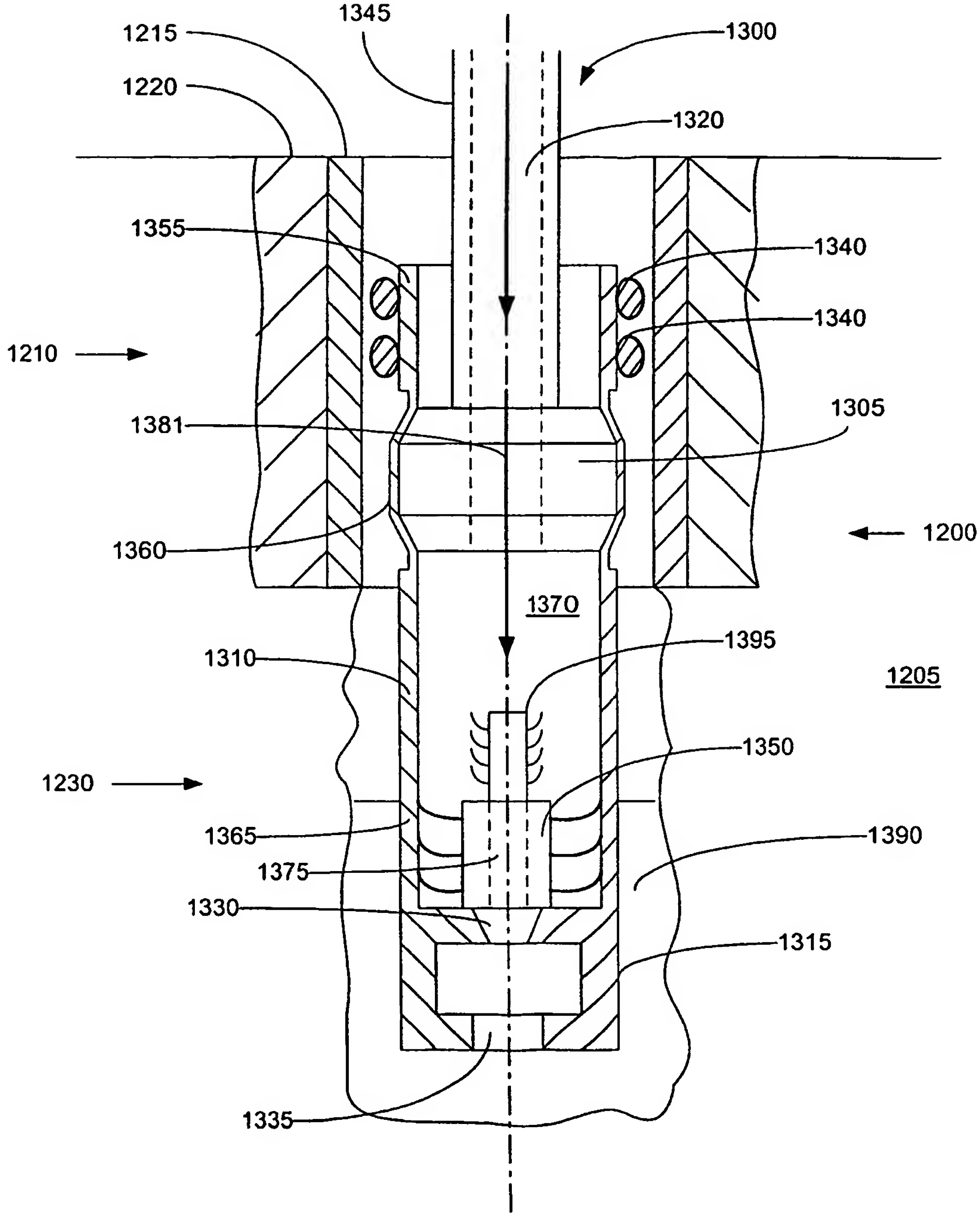
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FIGURE 11e

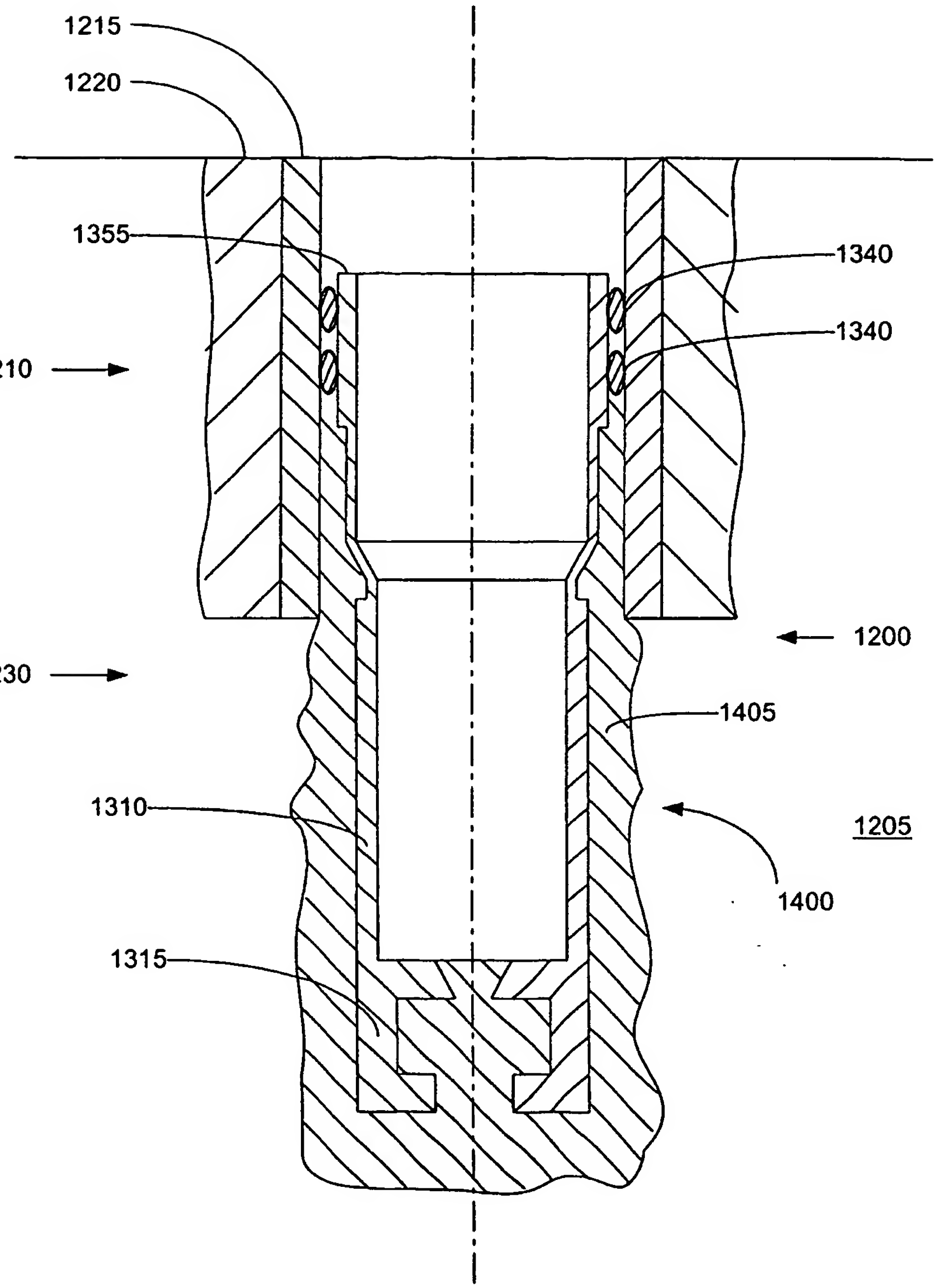
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FIGURE 11f

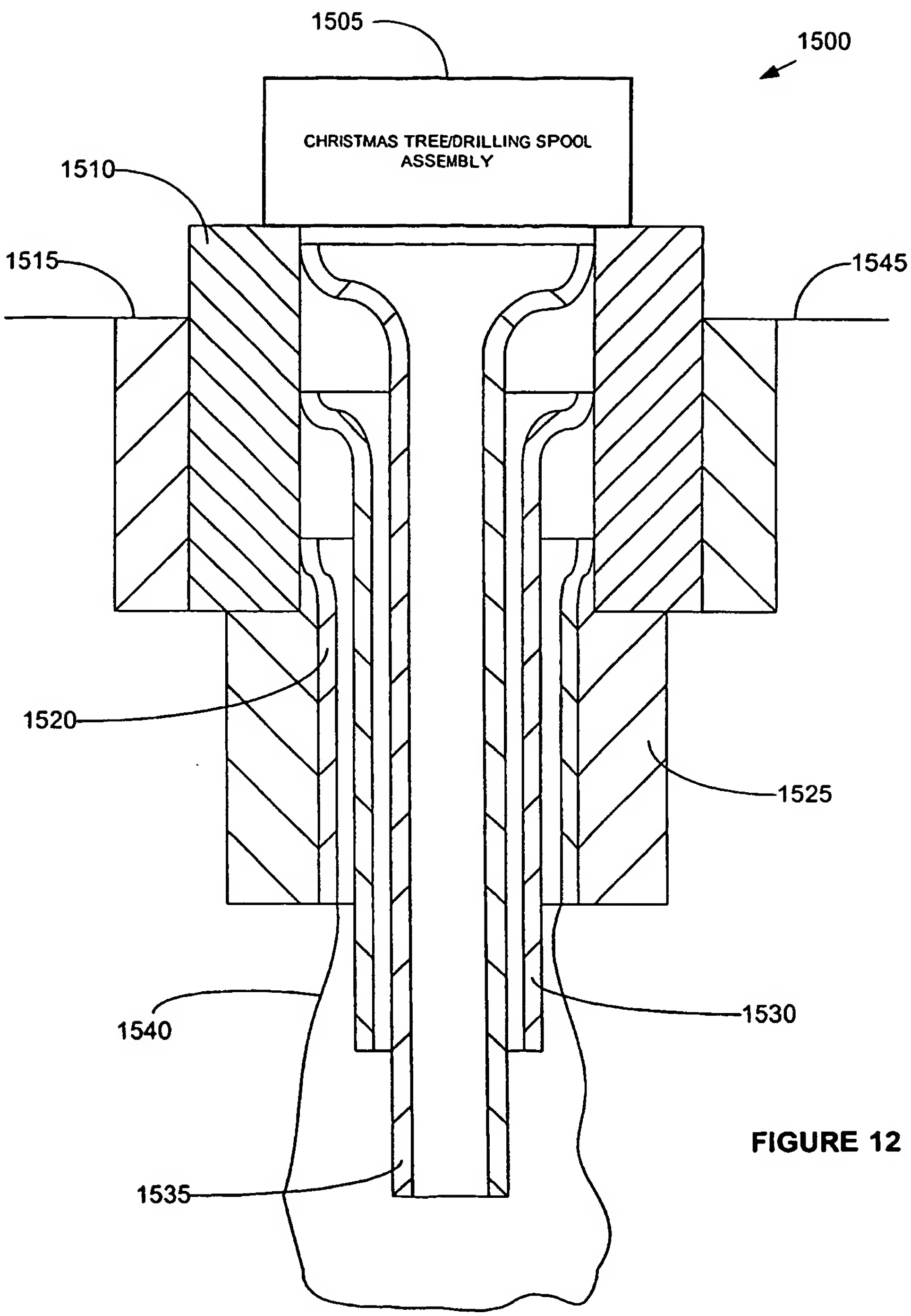
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FIGURE 12

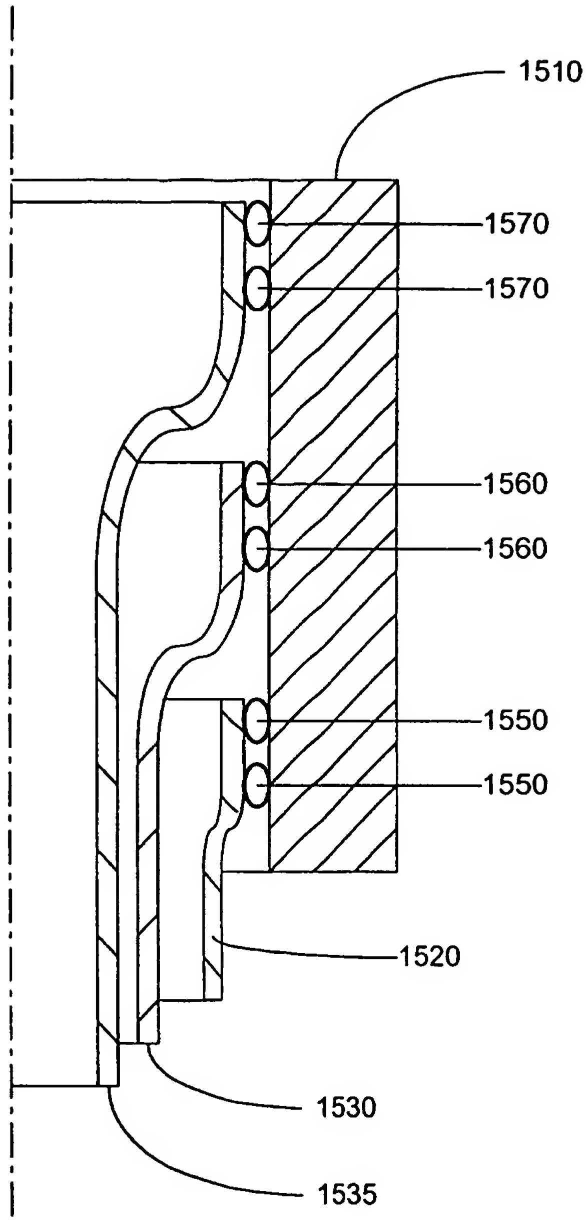

FIGURE 13

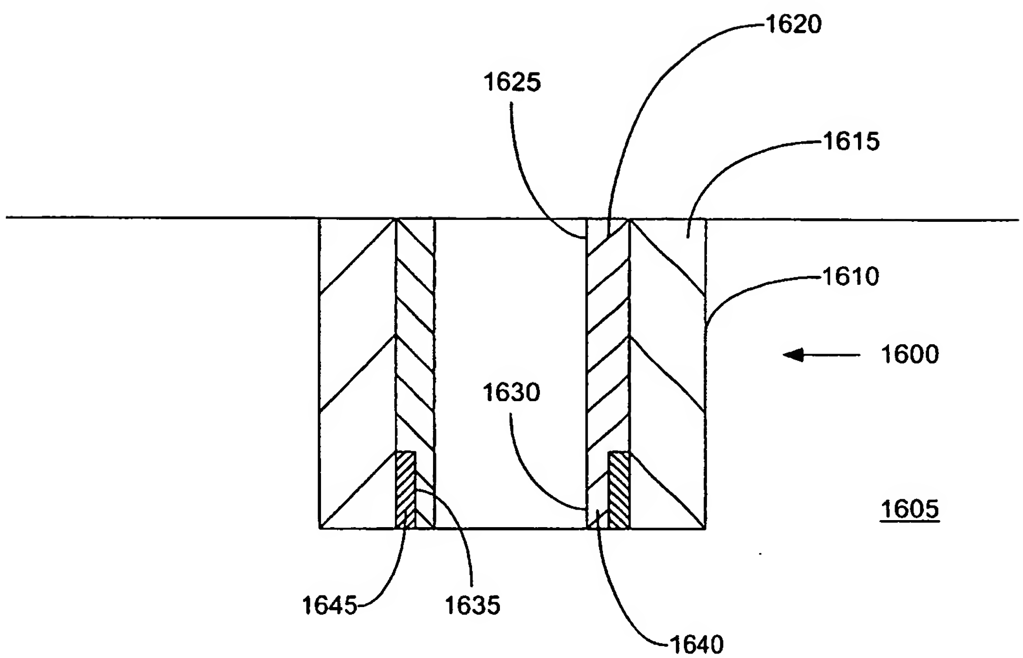

FIGURE 14a

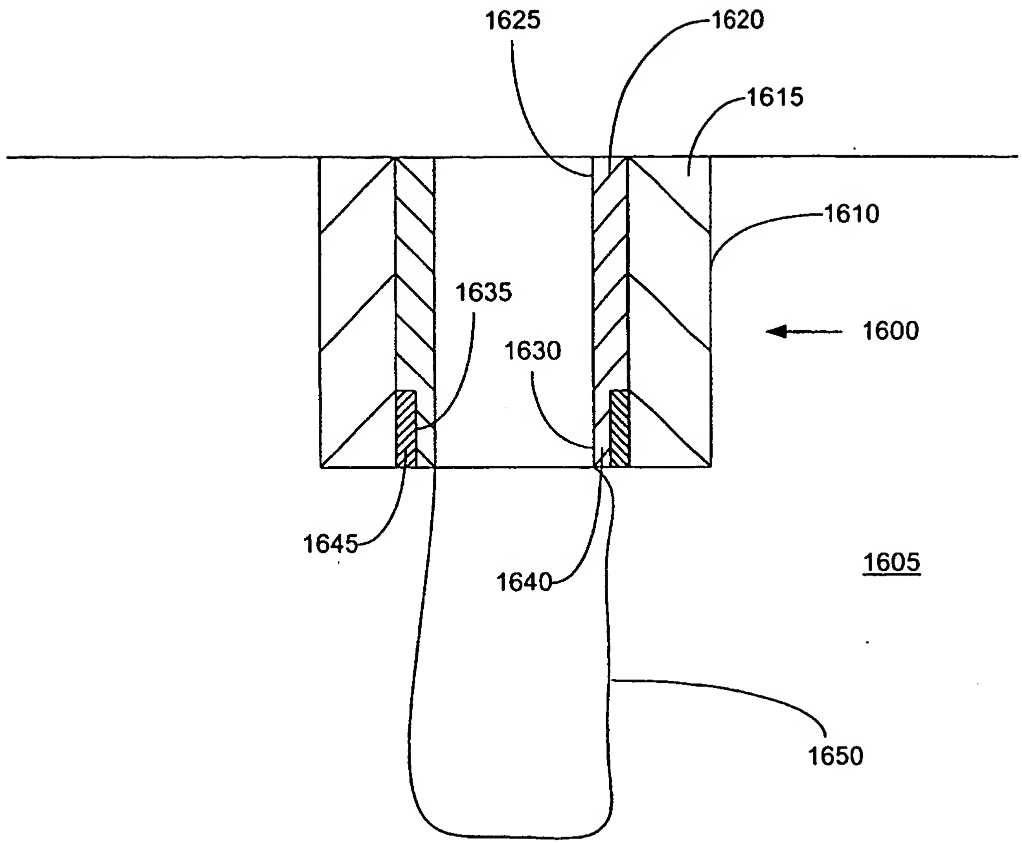

FIGURE 14b

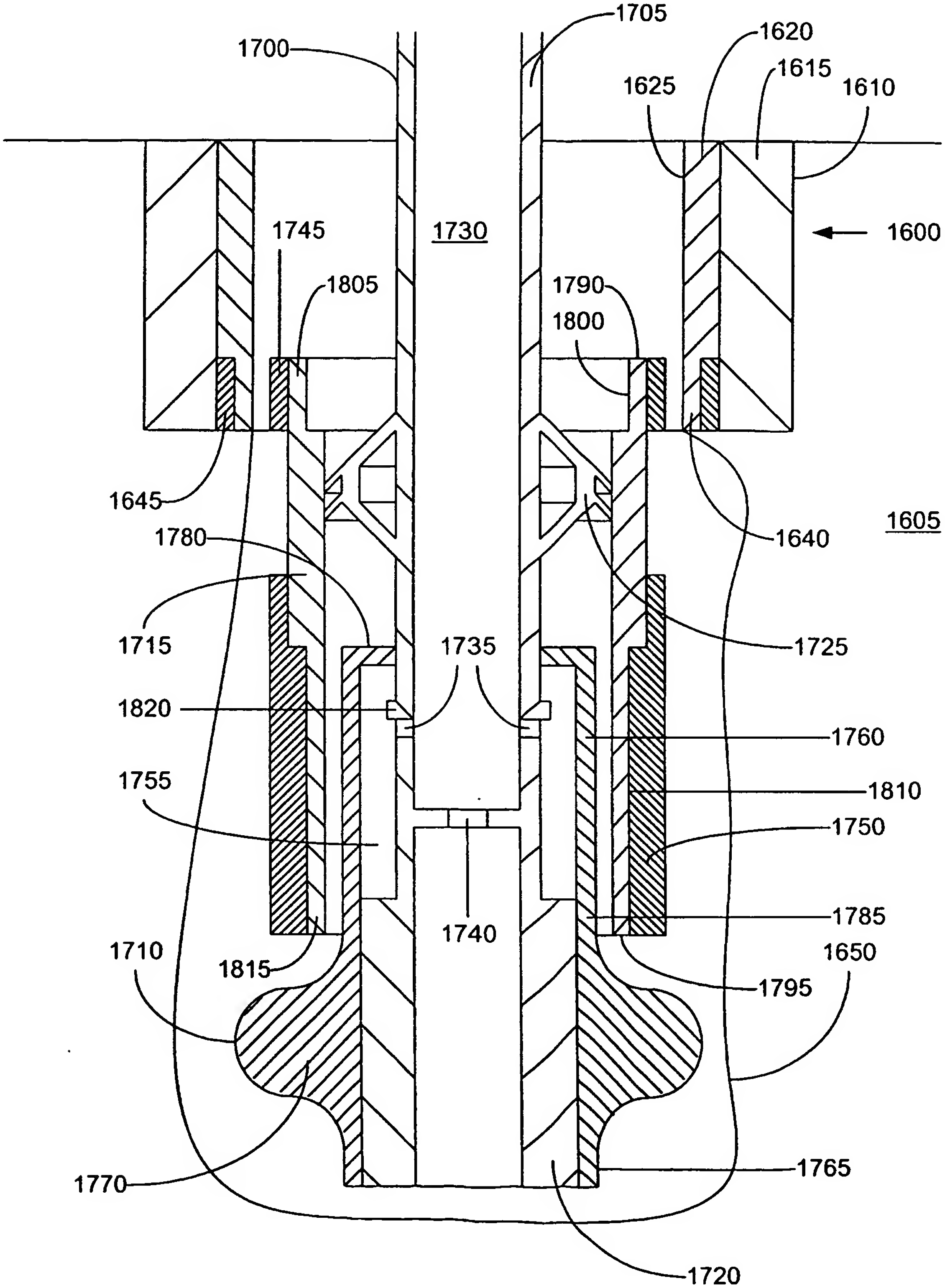

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FIGURE 14c

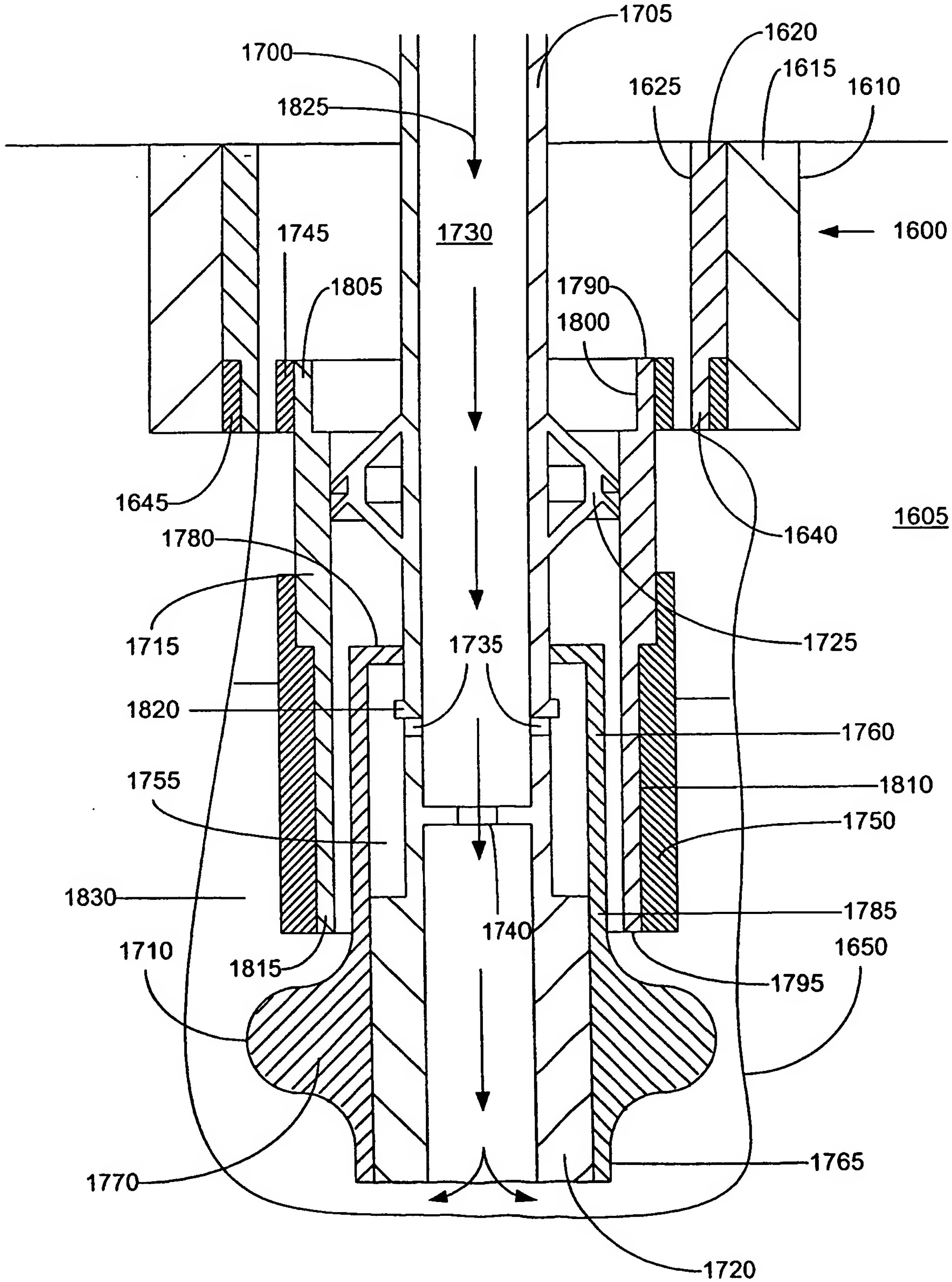
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FIGURE 14d

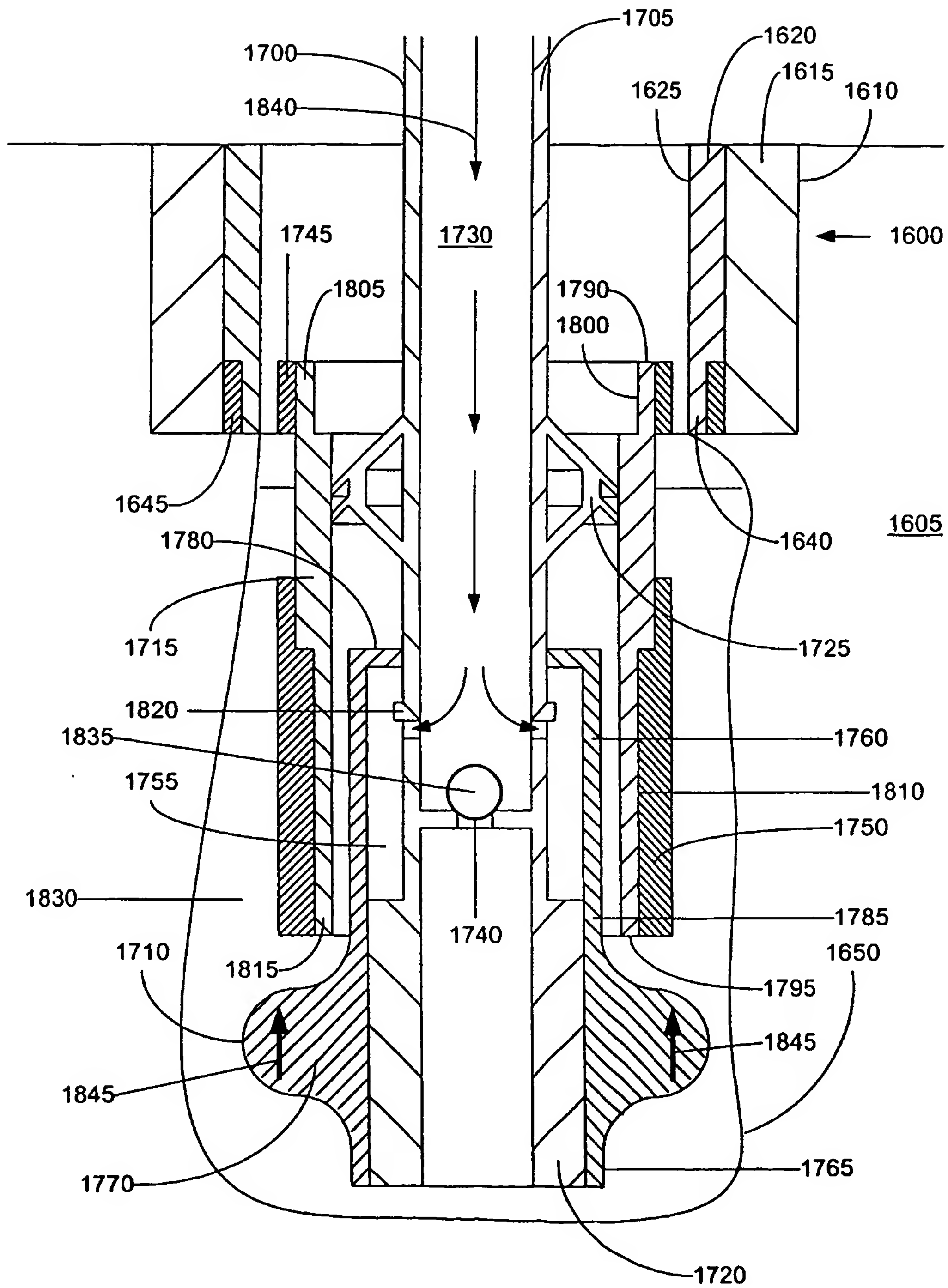
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FIGURE 14e

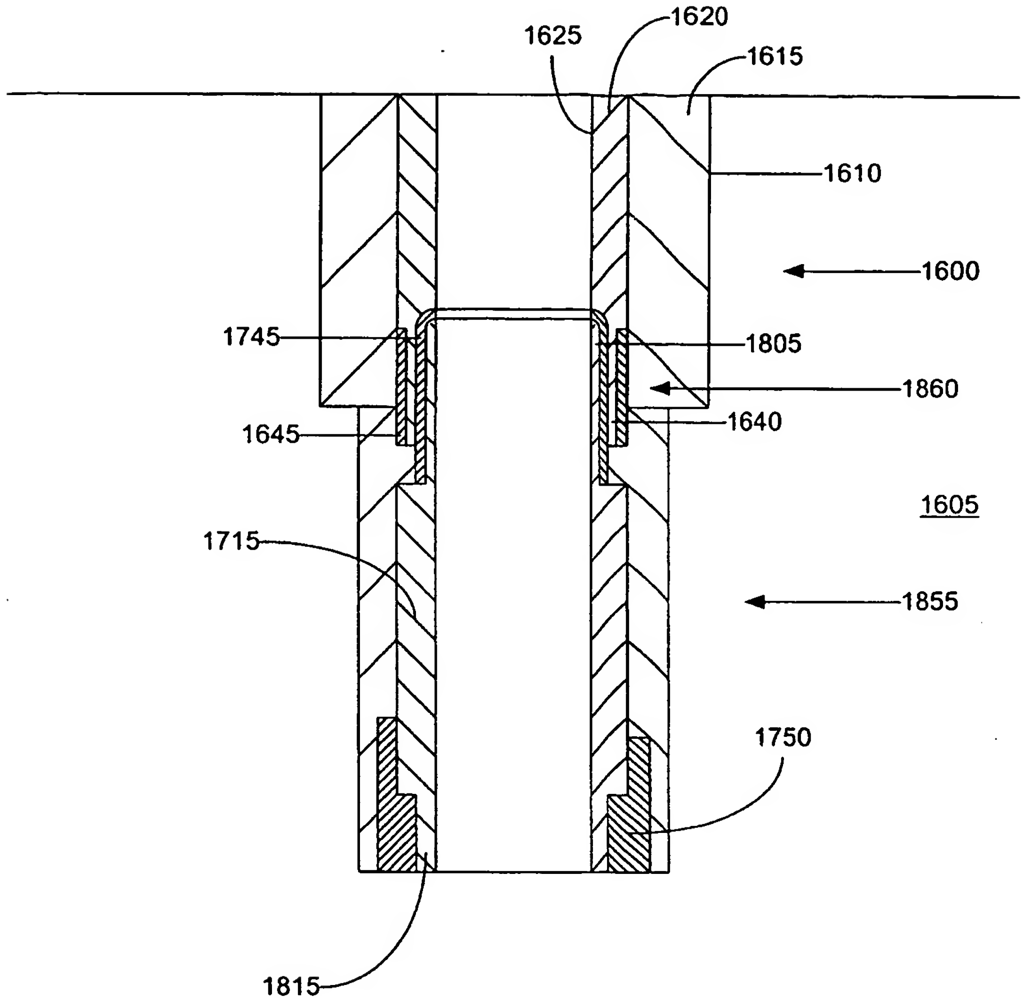
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FIGURE 14f

23 11 00 71777

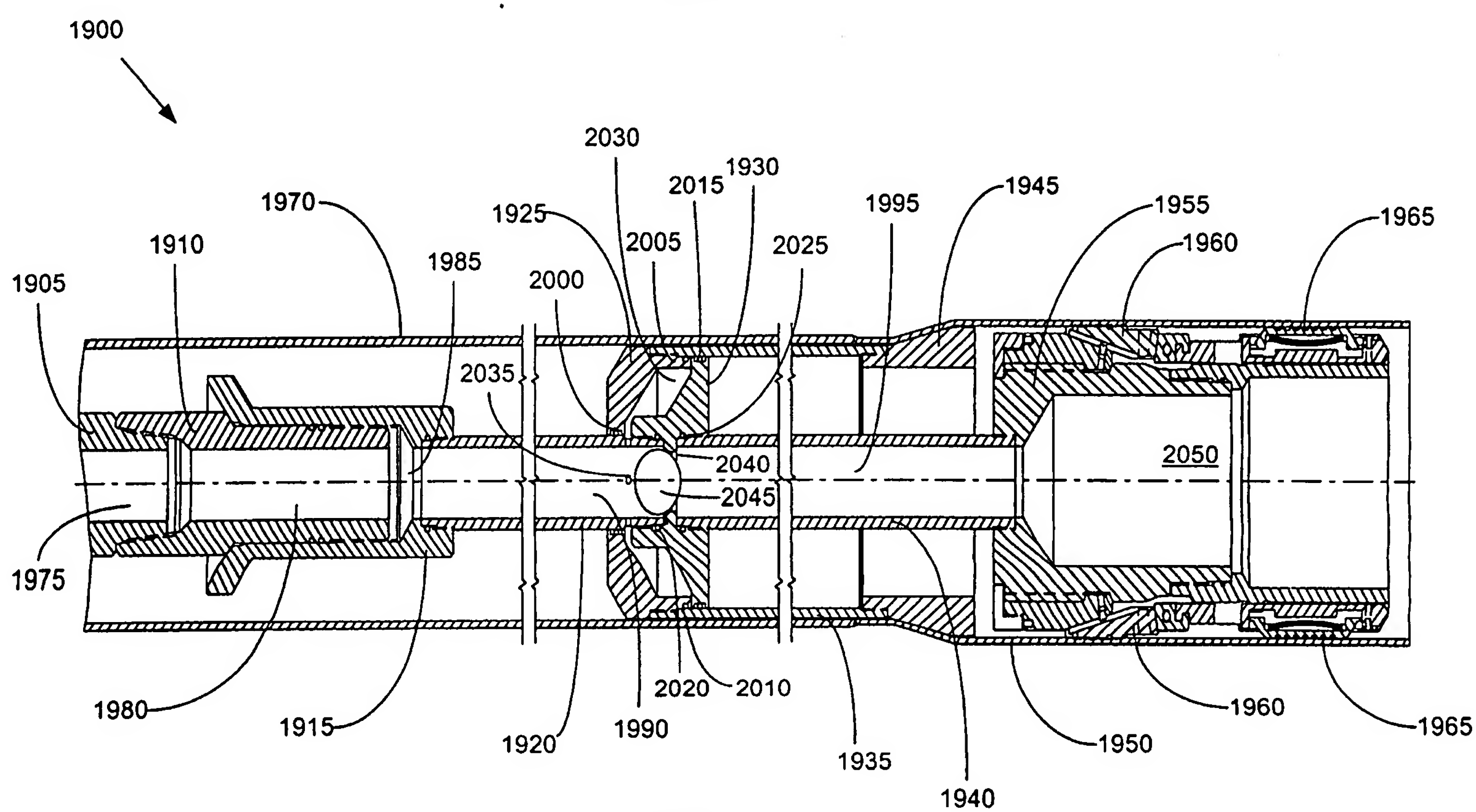

FIGURE 15

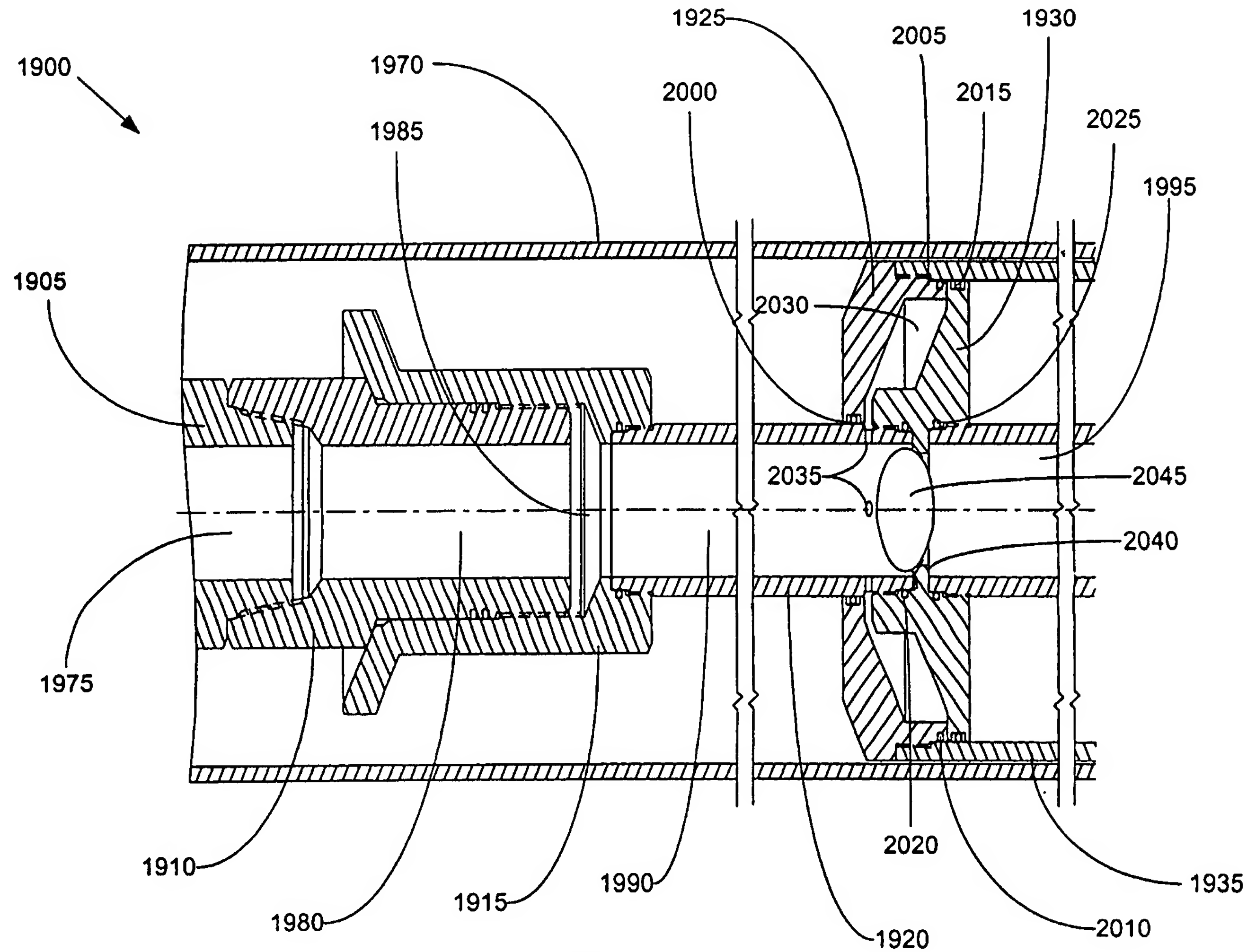

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FIGURE 15a

23 11 00 T1777

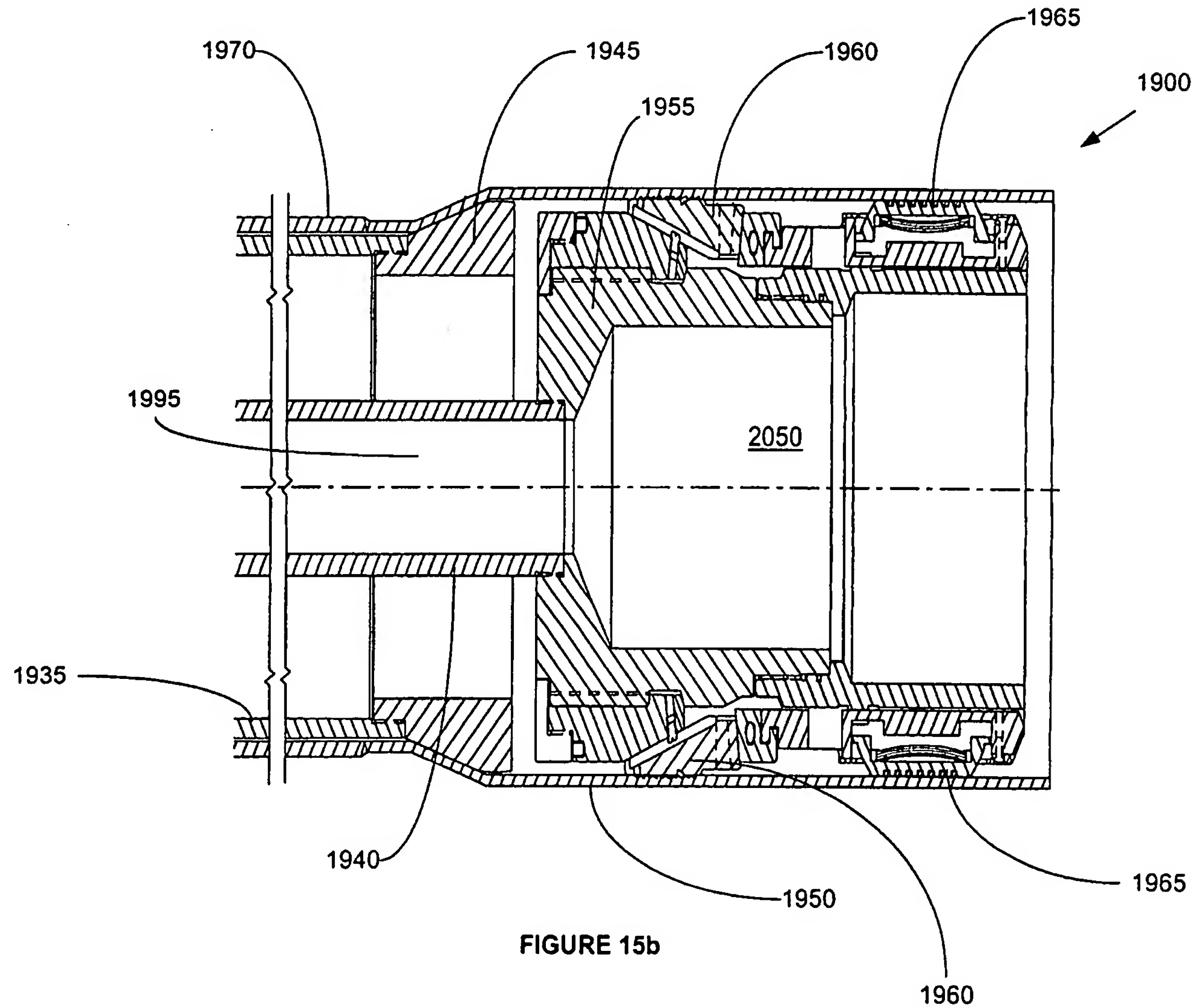


FIGURE 15b

23 11 00 71777

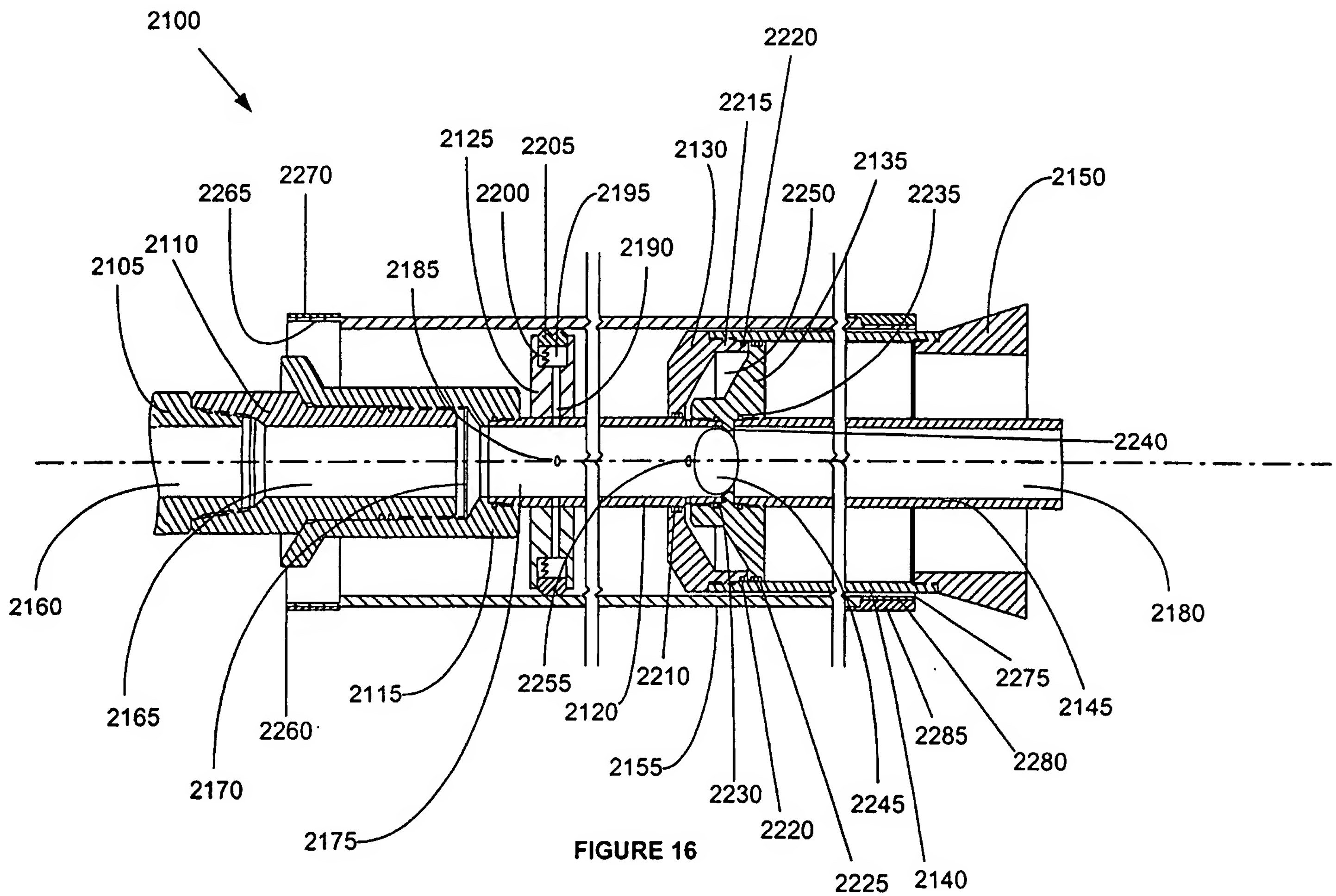
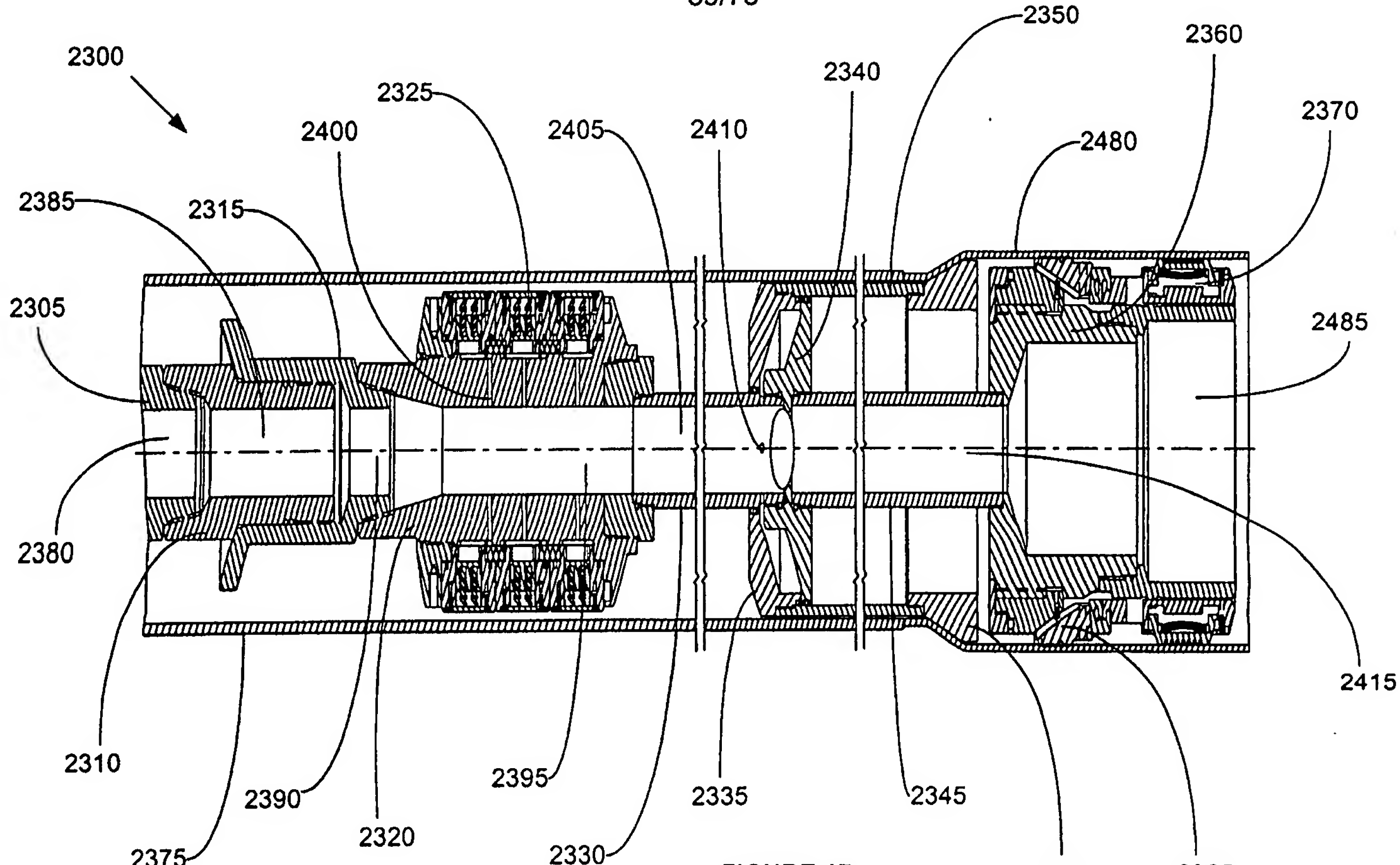


FIGURE 16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2365
2375

FIGURE 17

23 11 00 71777

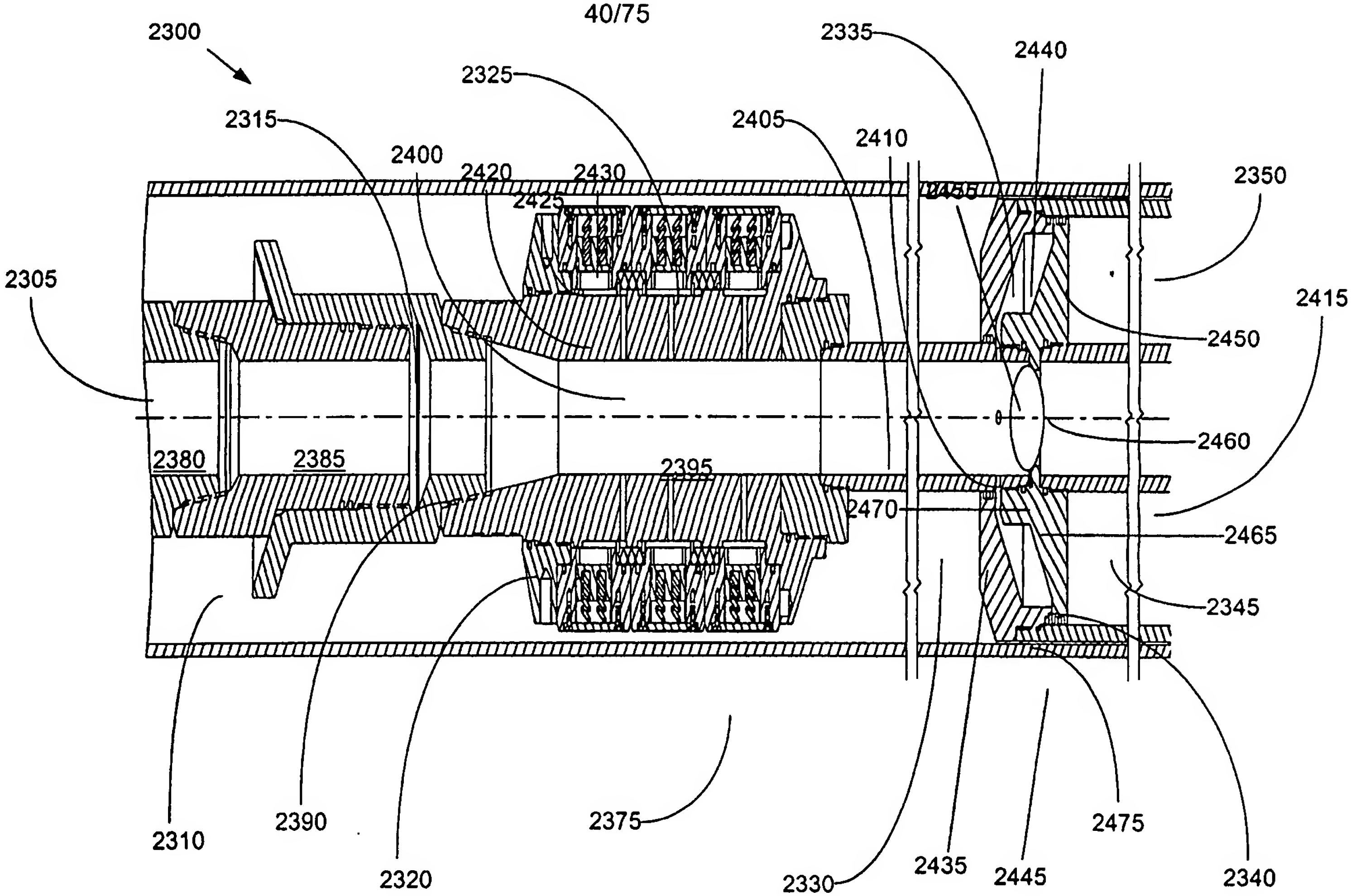
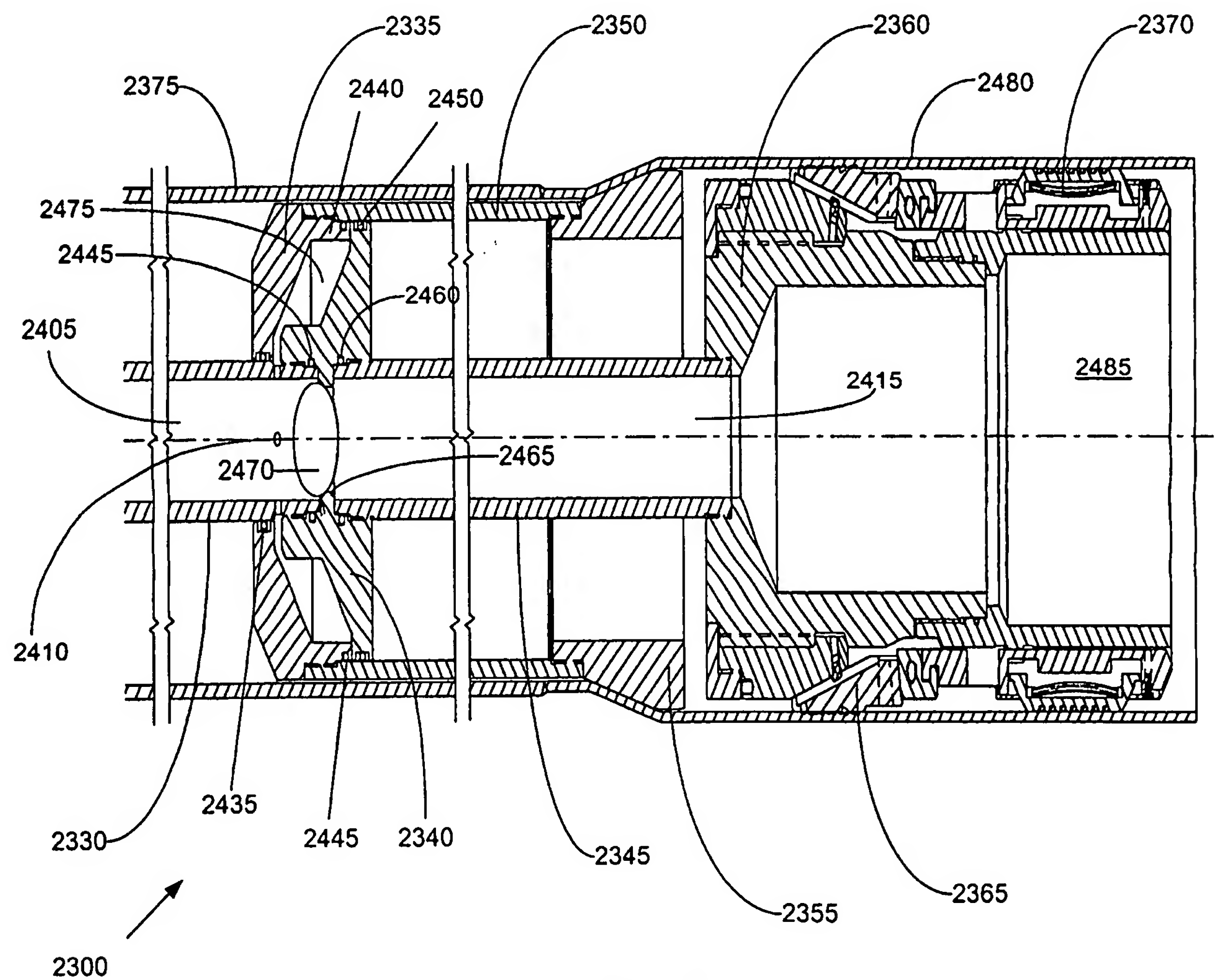


FIGURE 17a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2345
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FIGURE 17b

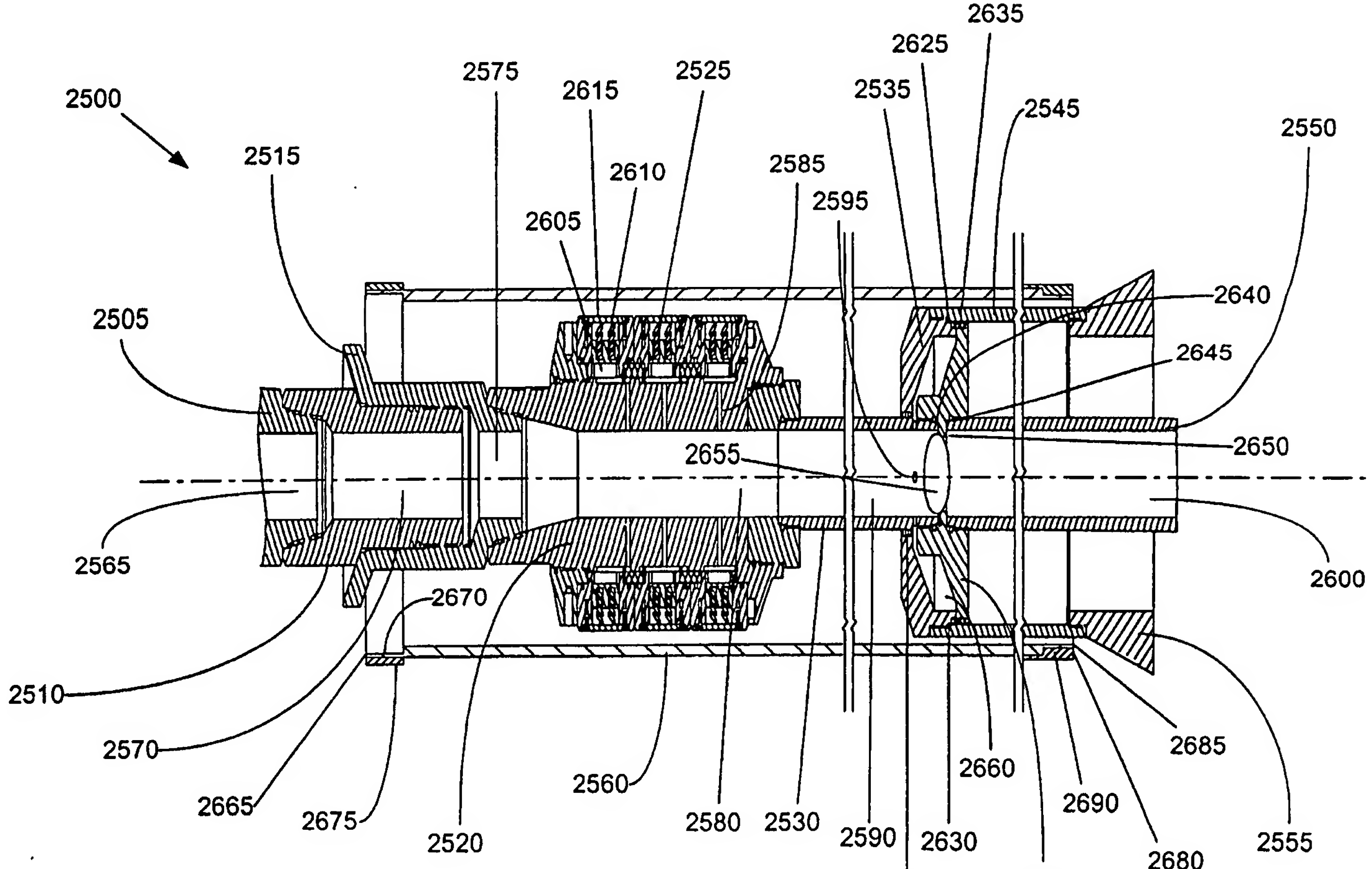
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FIGURE 18

23 11 00 71777

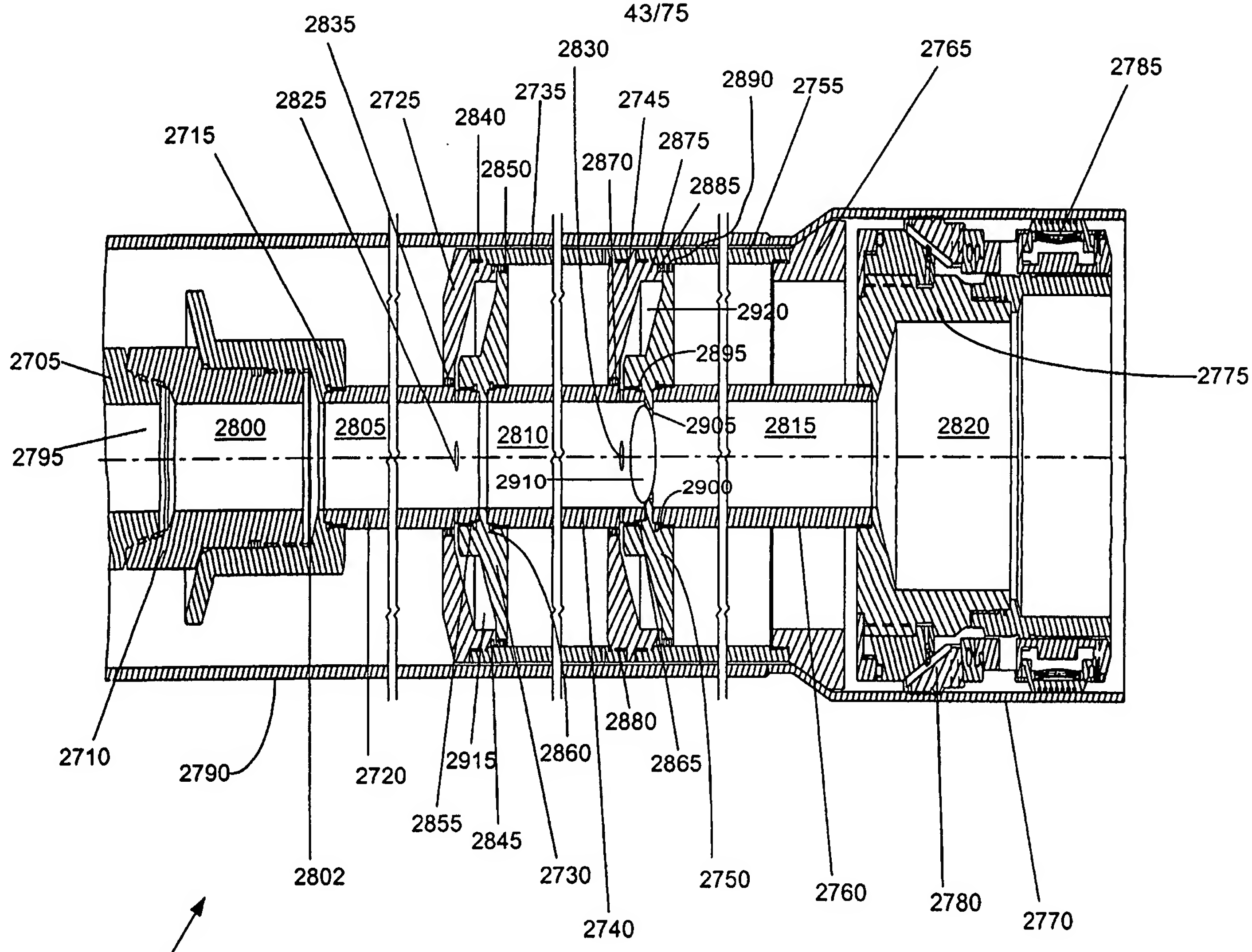


FIGURE 19

23 11 00 71777

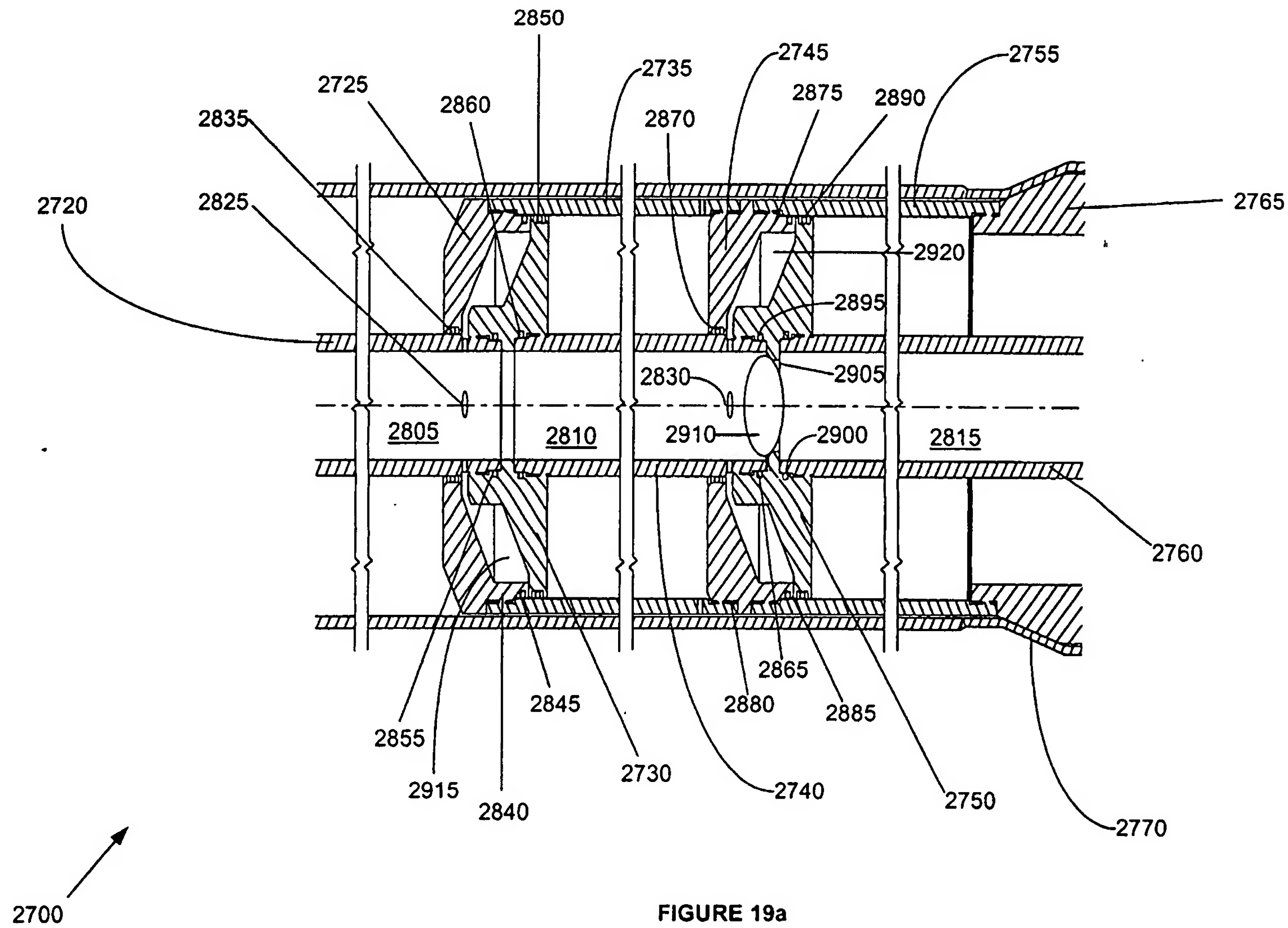


FIGURE 19a

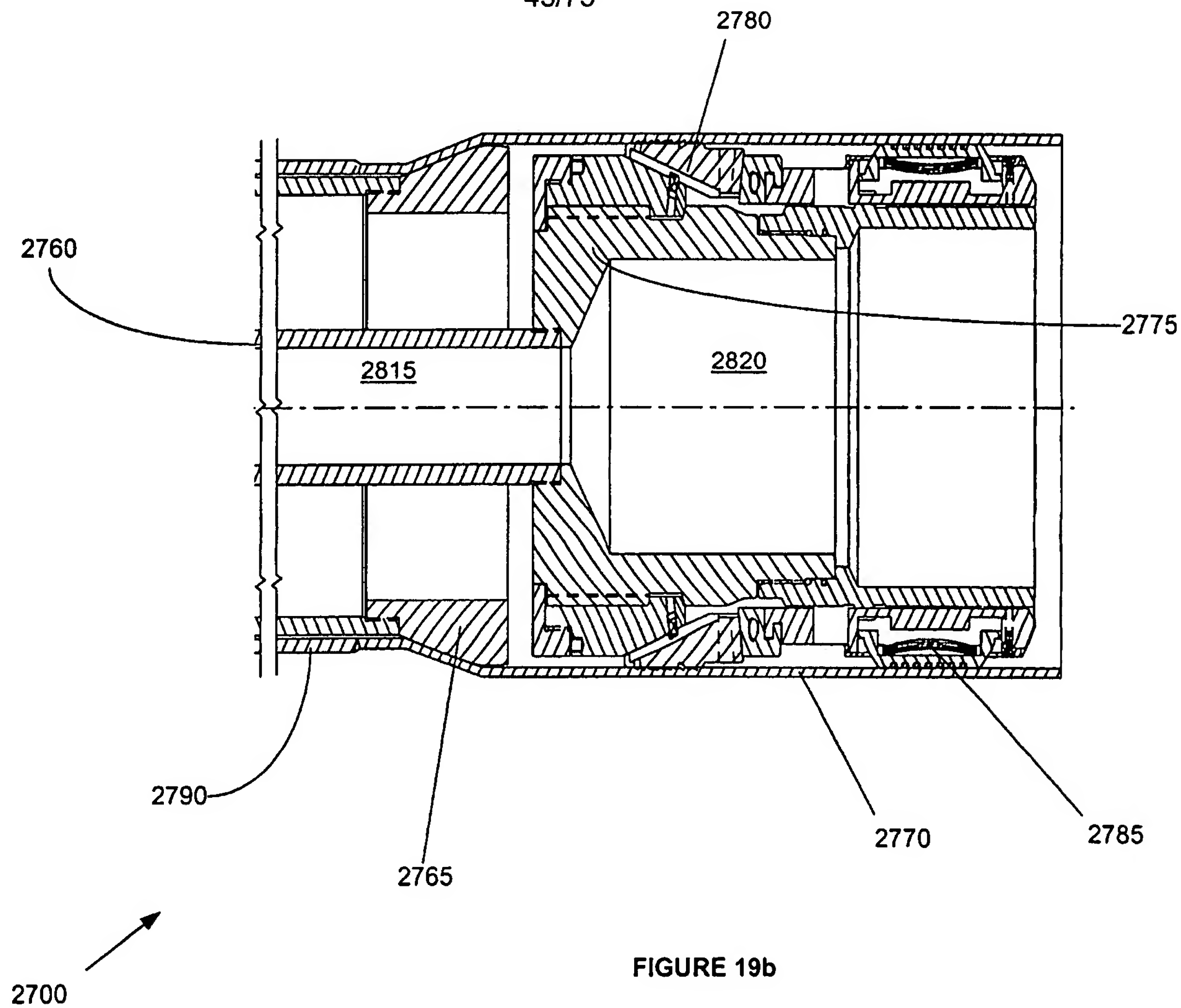


FIGURE 19b

23 11 00 71777

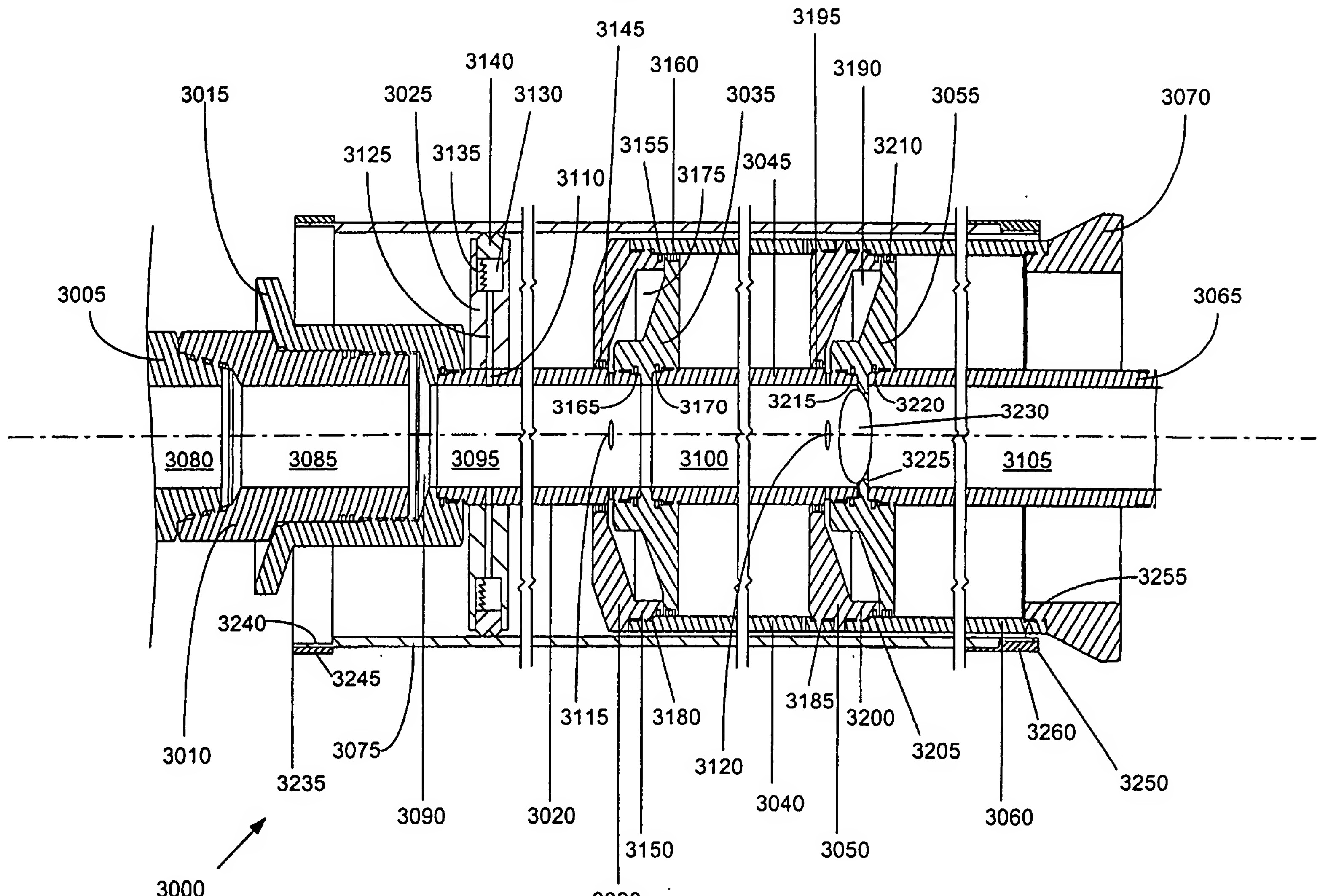
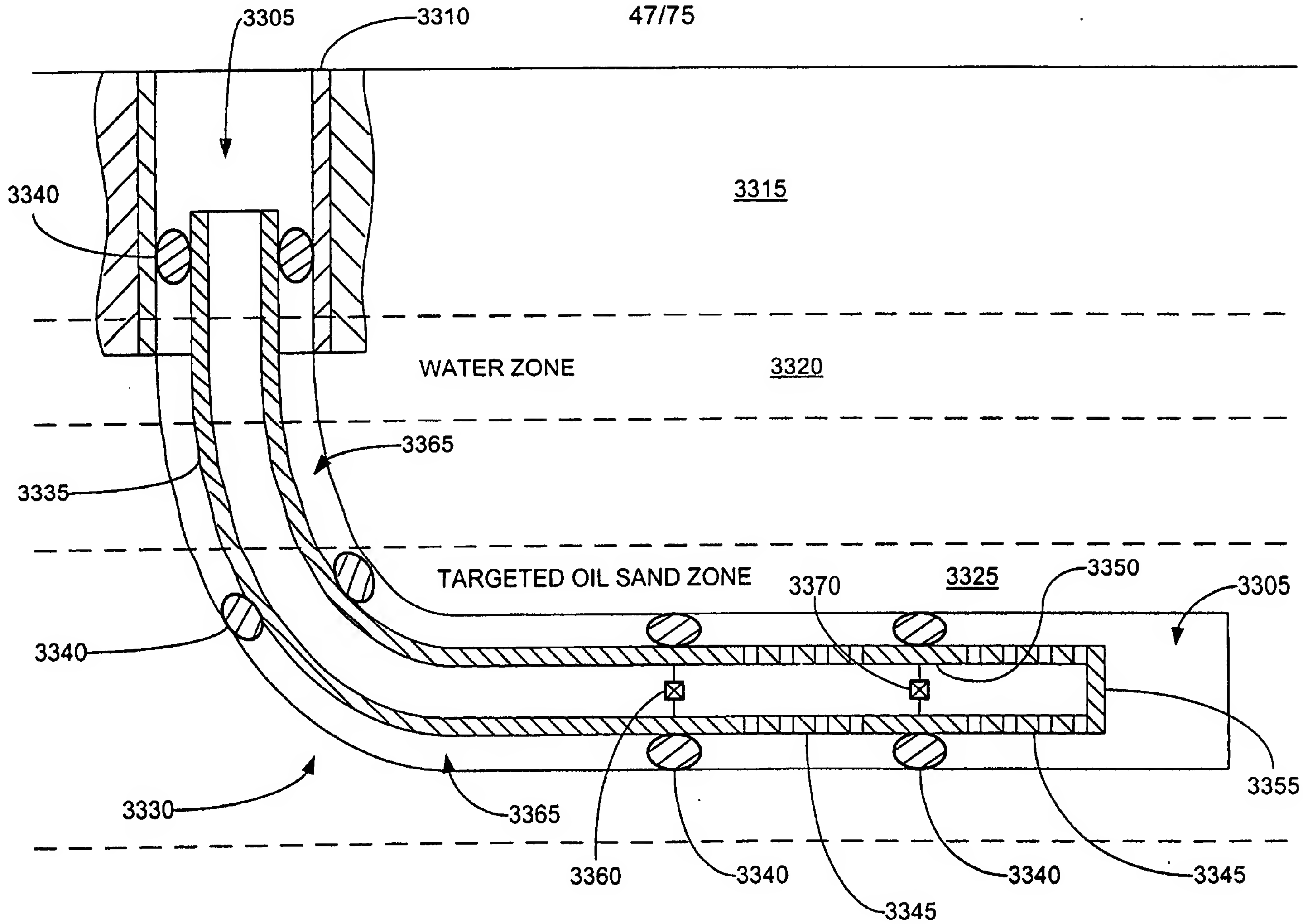


FIGURE 20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TARGETED OIL SAND ZONE
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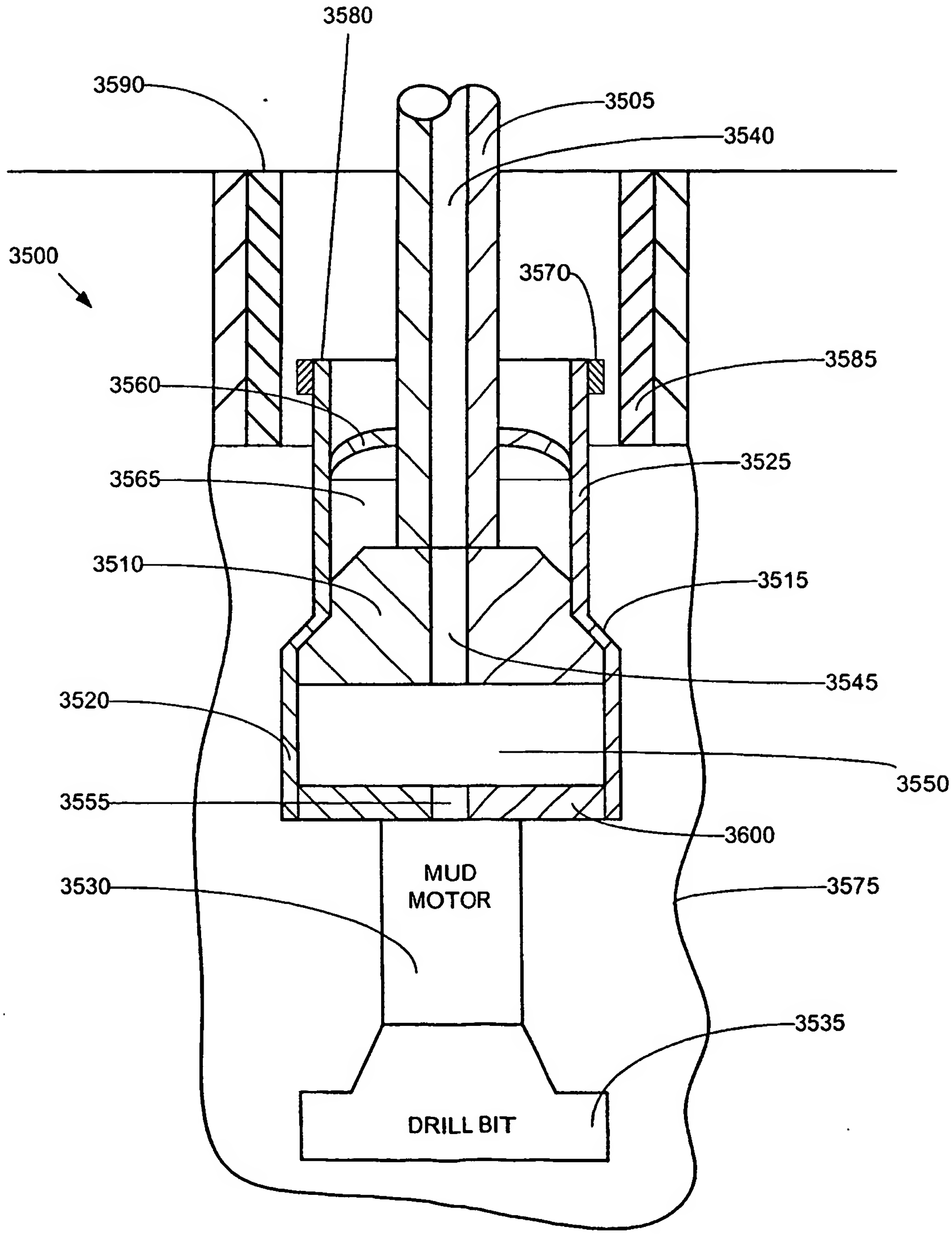
FIGURE 21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MUD
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3575
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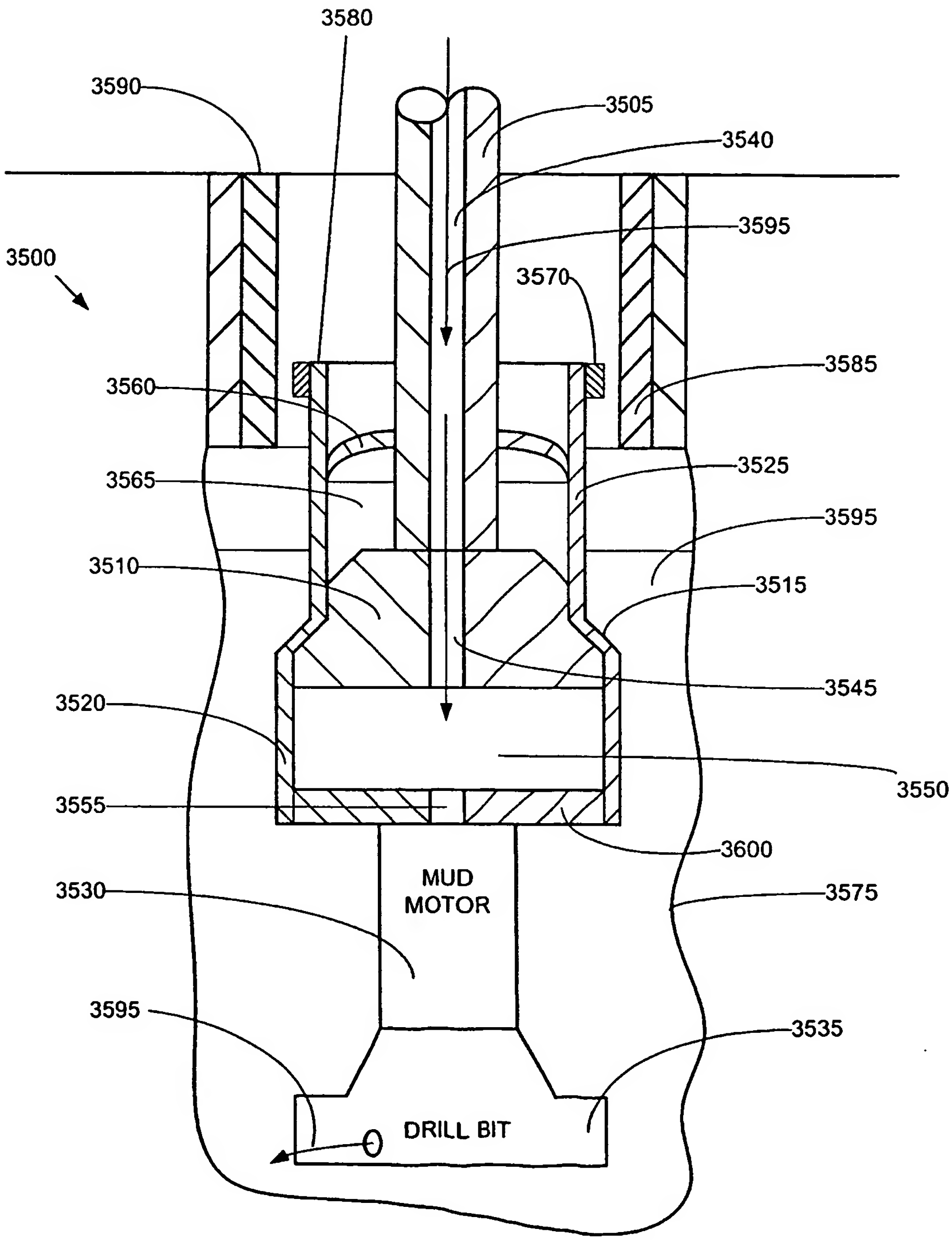
DRILL BIT

FIGURE 22A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MUD
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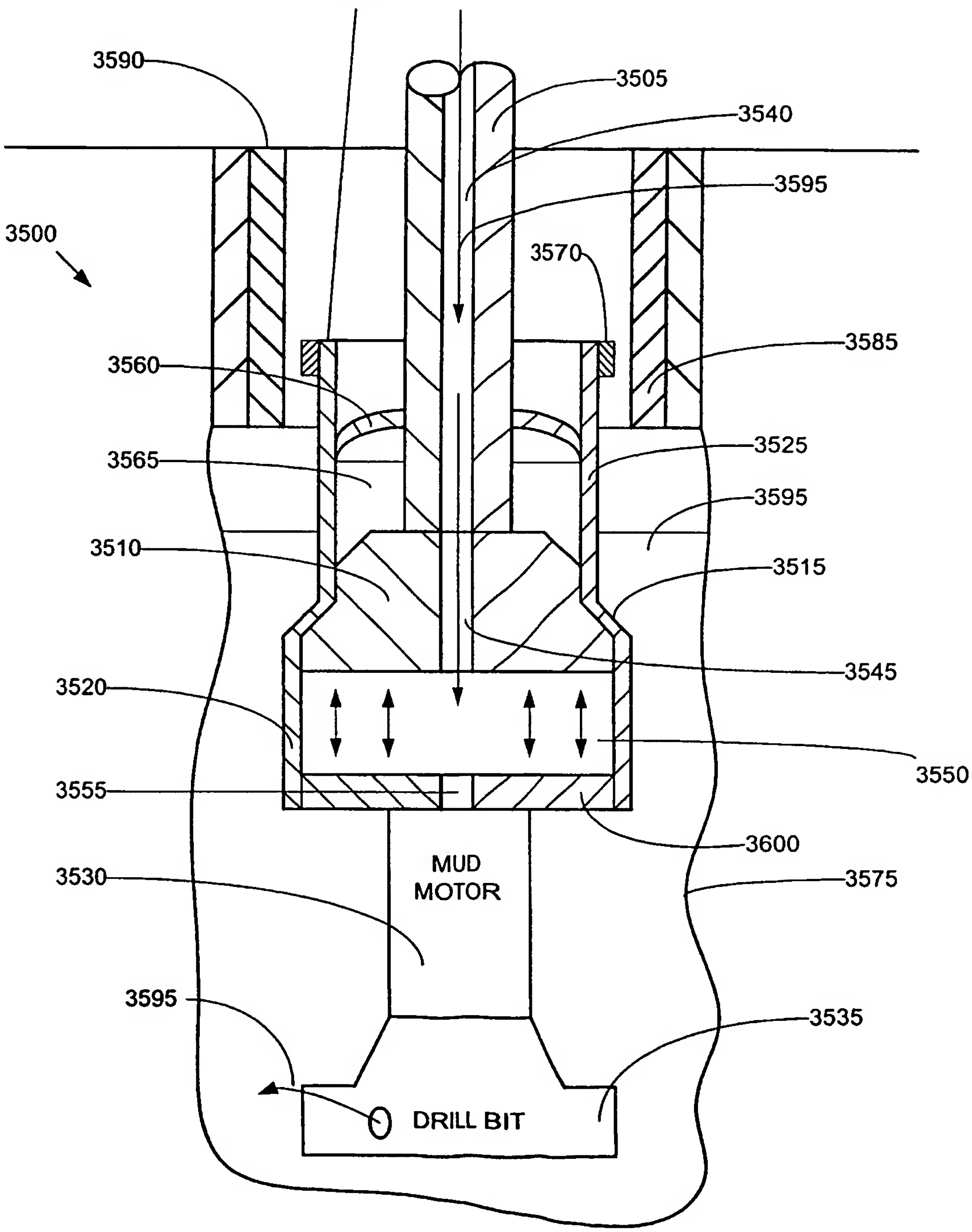
DRILL BIT

FIGURE 22B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MUD
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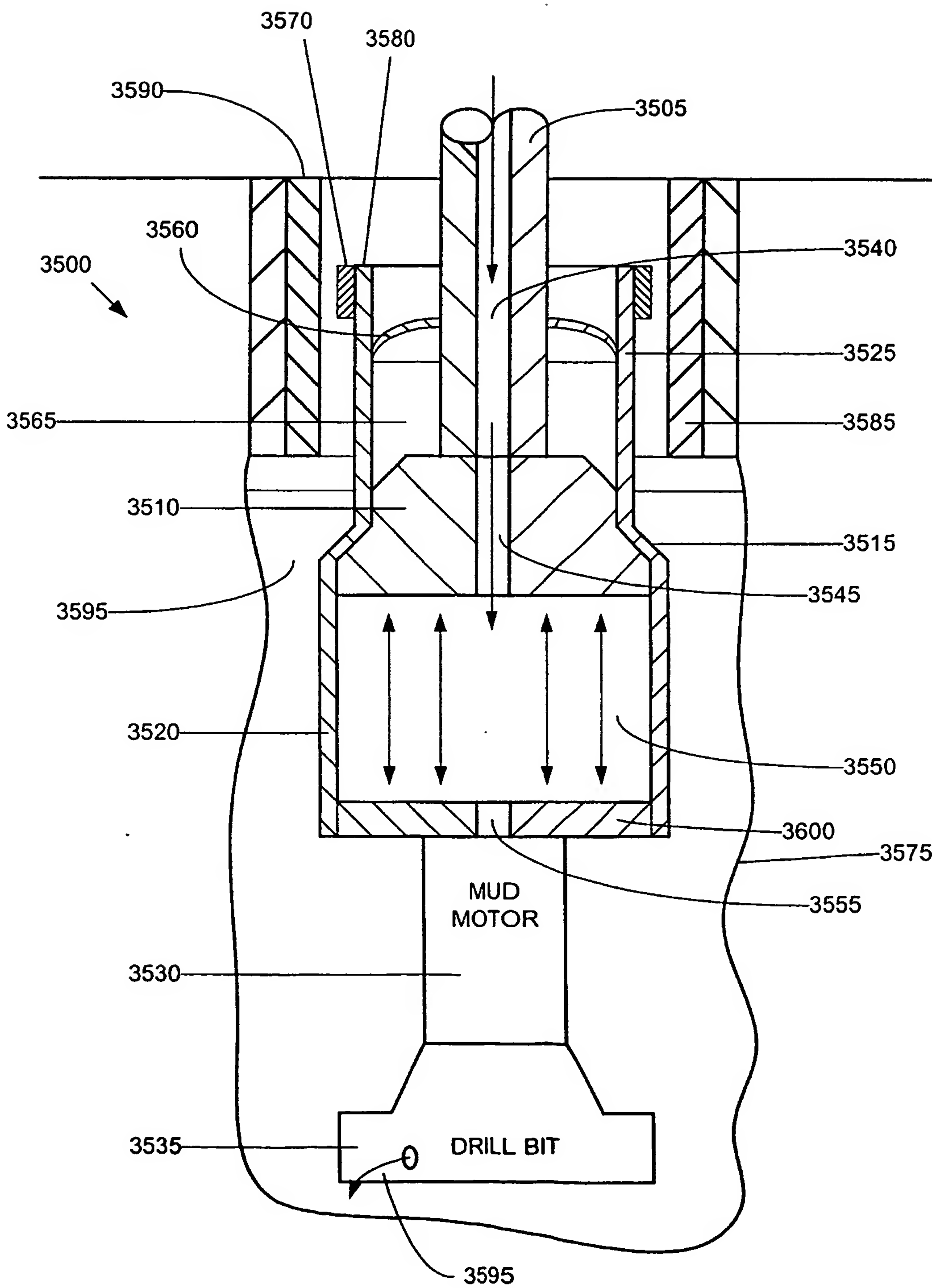
3535
DRILL BIT

FIGURE 22C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MUD
MOTOR
3530
3535
DRILL BIT
3595

FIGURE 22D

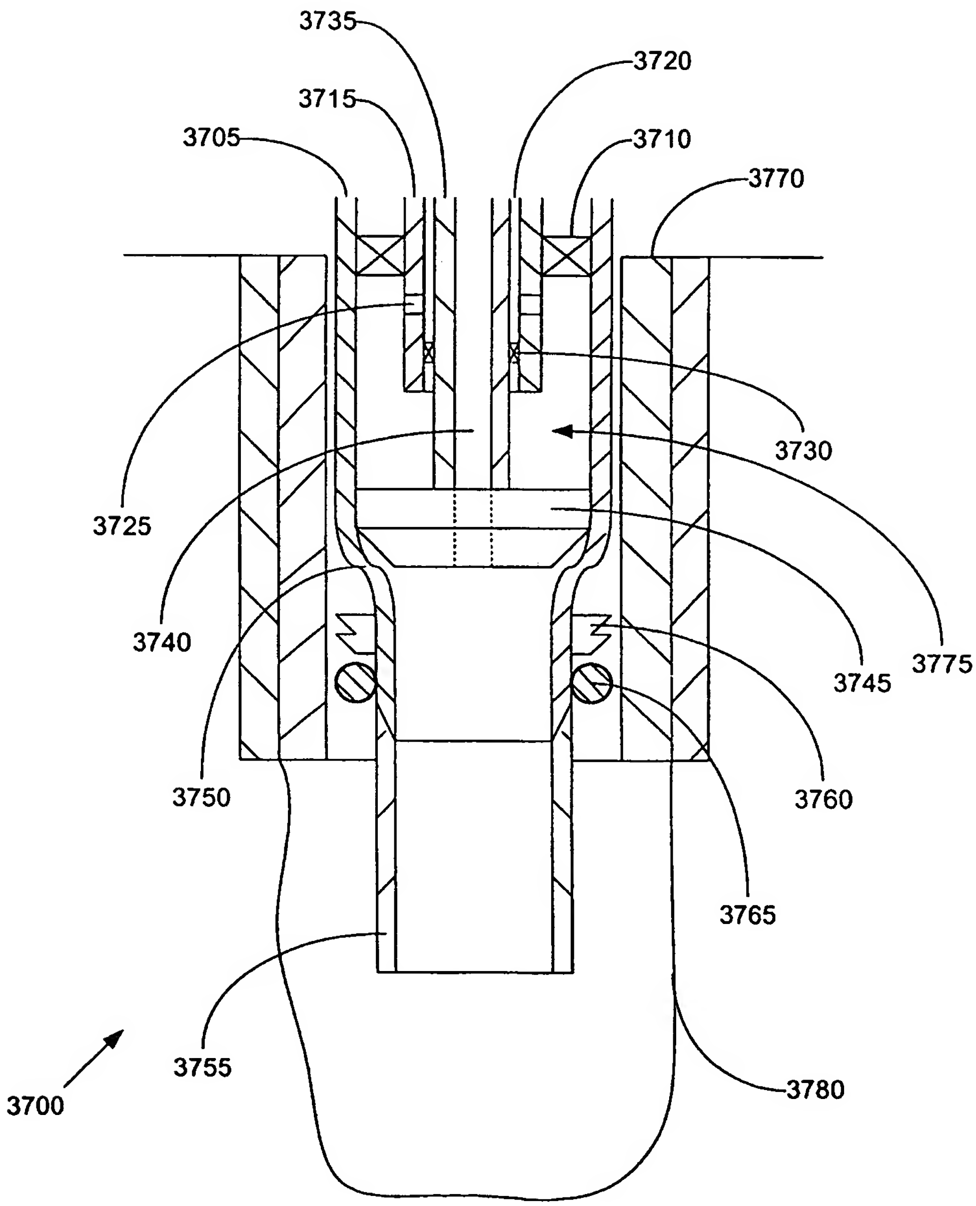
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FIGURE 23A

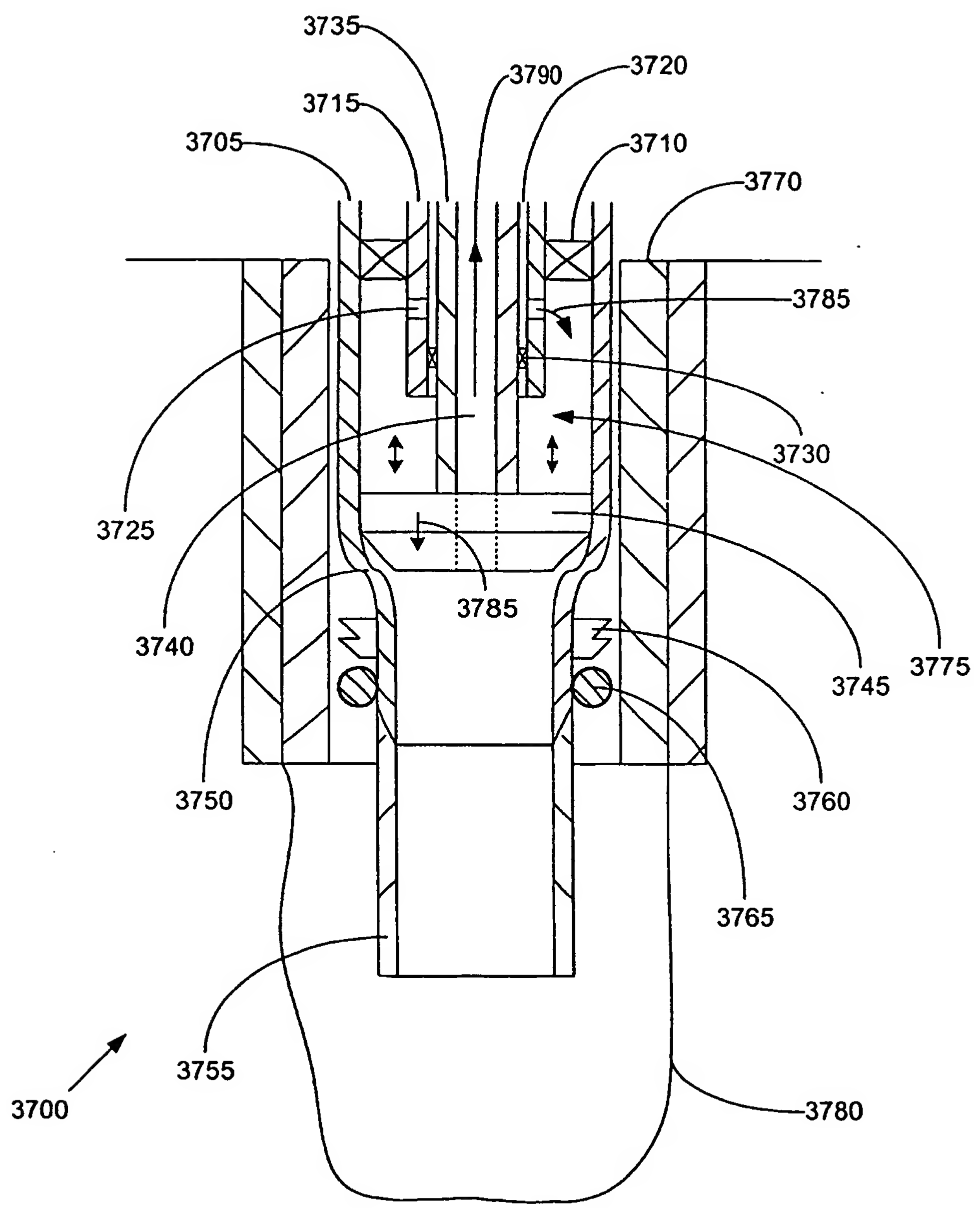
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FIGURE 23B

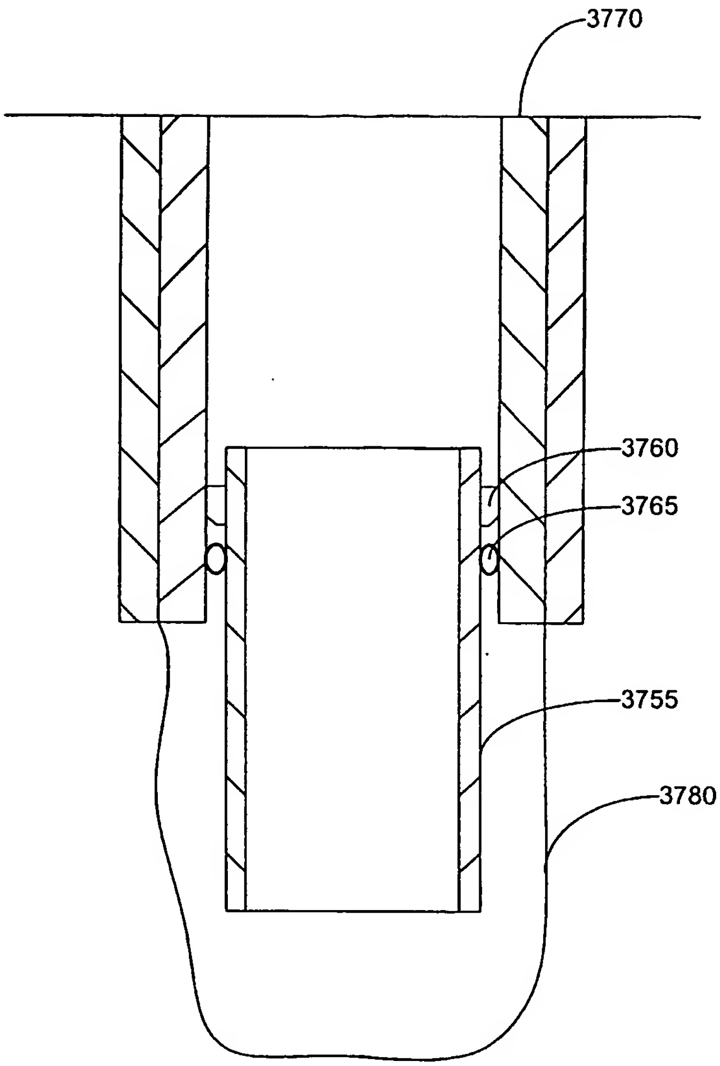

FIGURE 23C

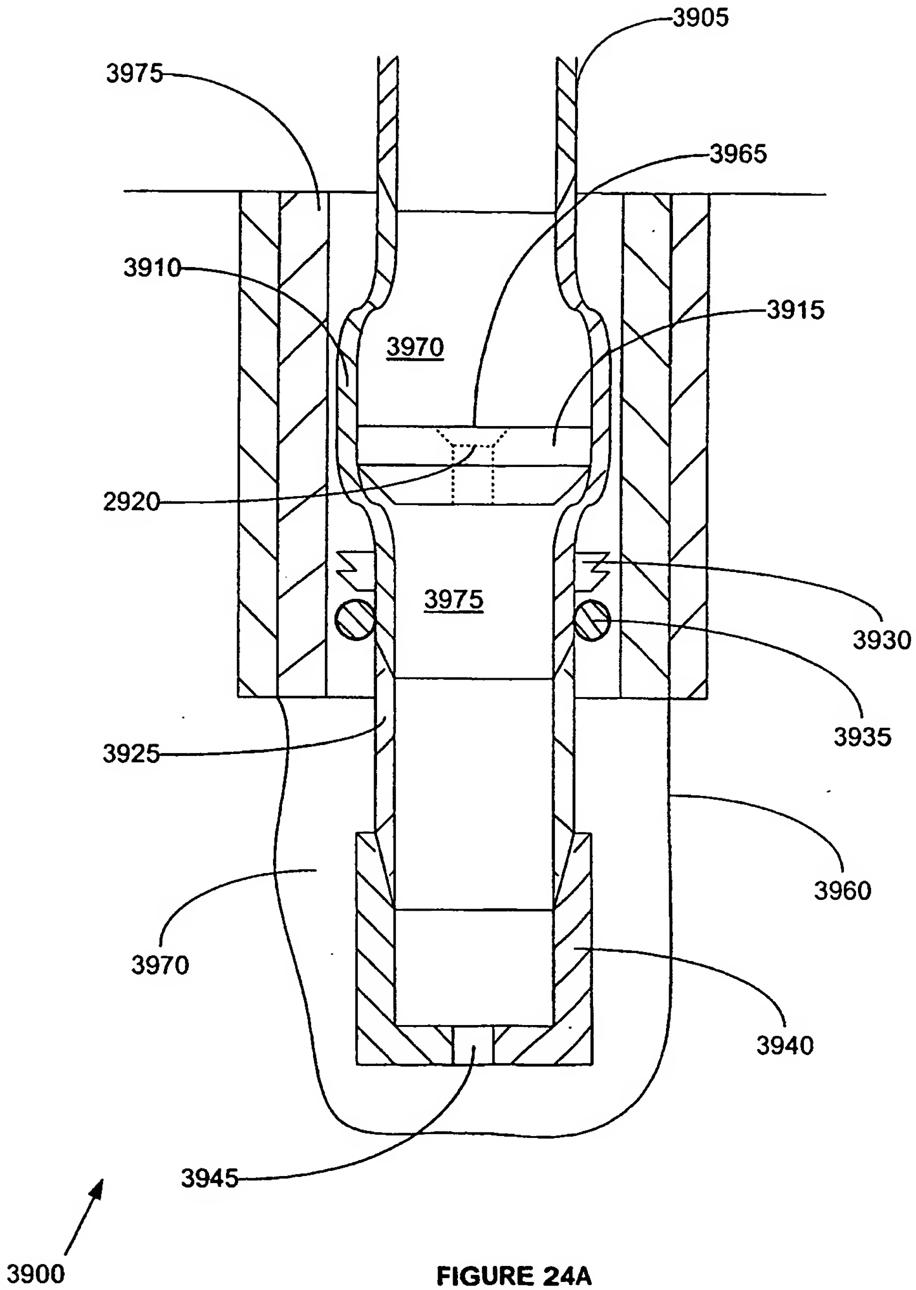
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FIGURE 24A

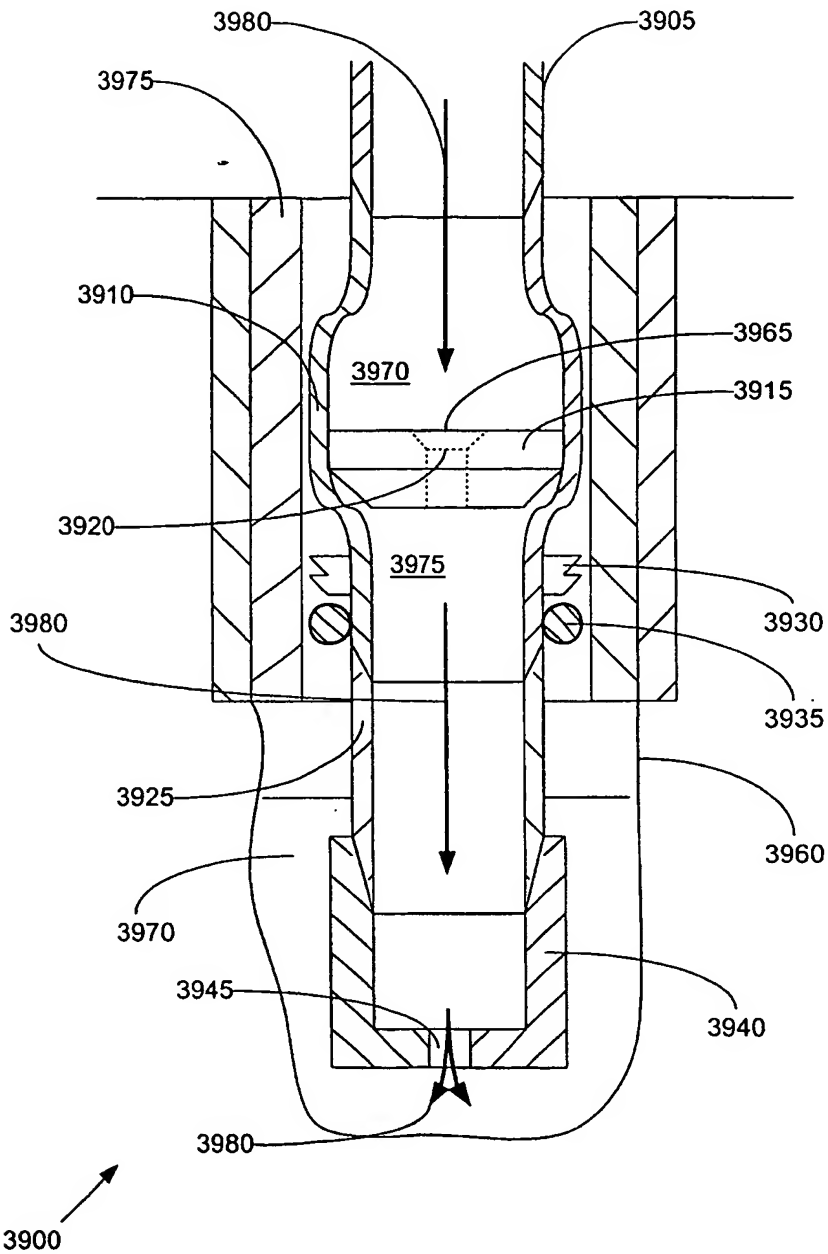

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FIGURE 24B

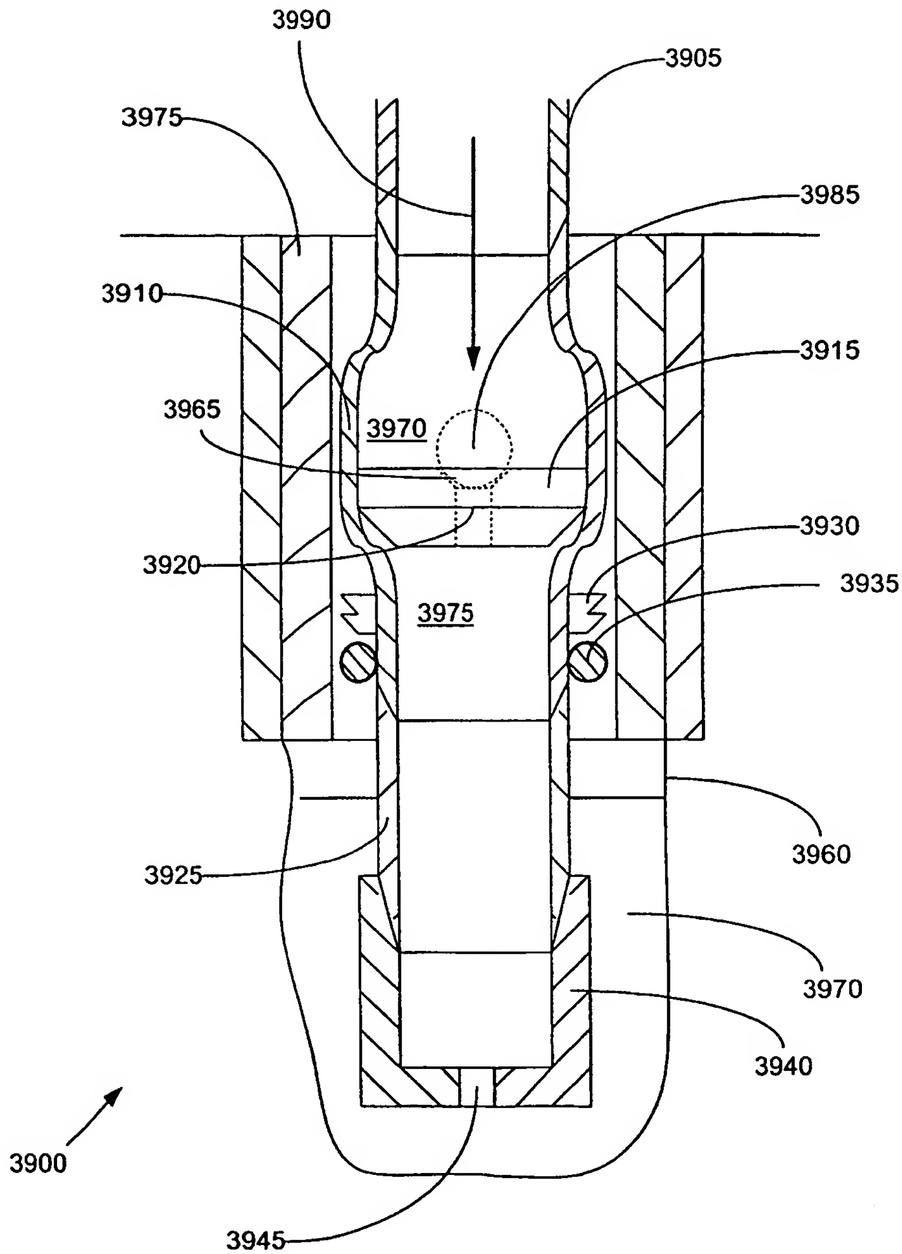

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FIGURE 24C

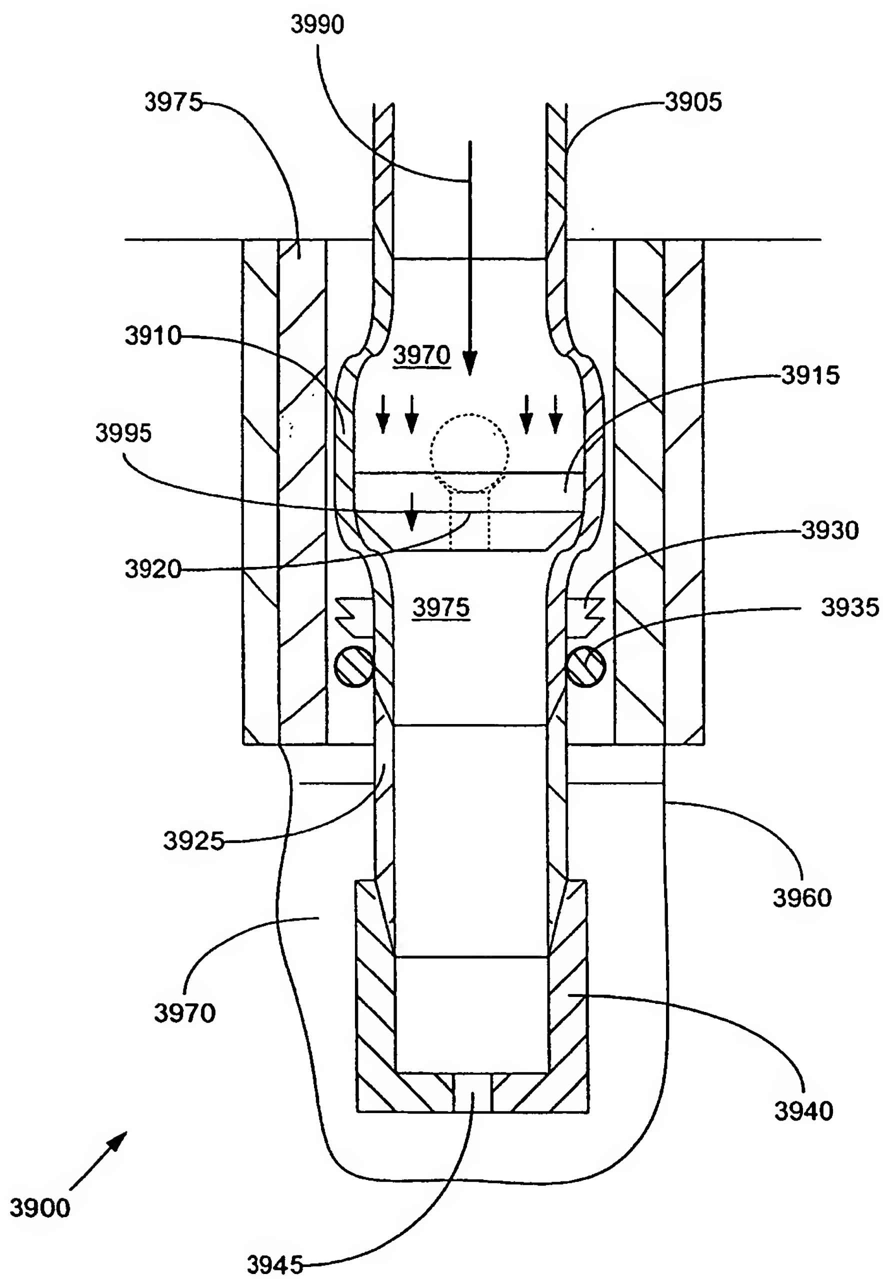
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FIGURE 24D

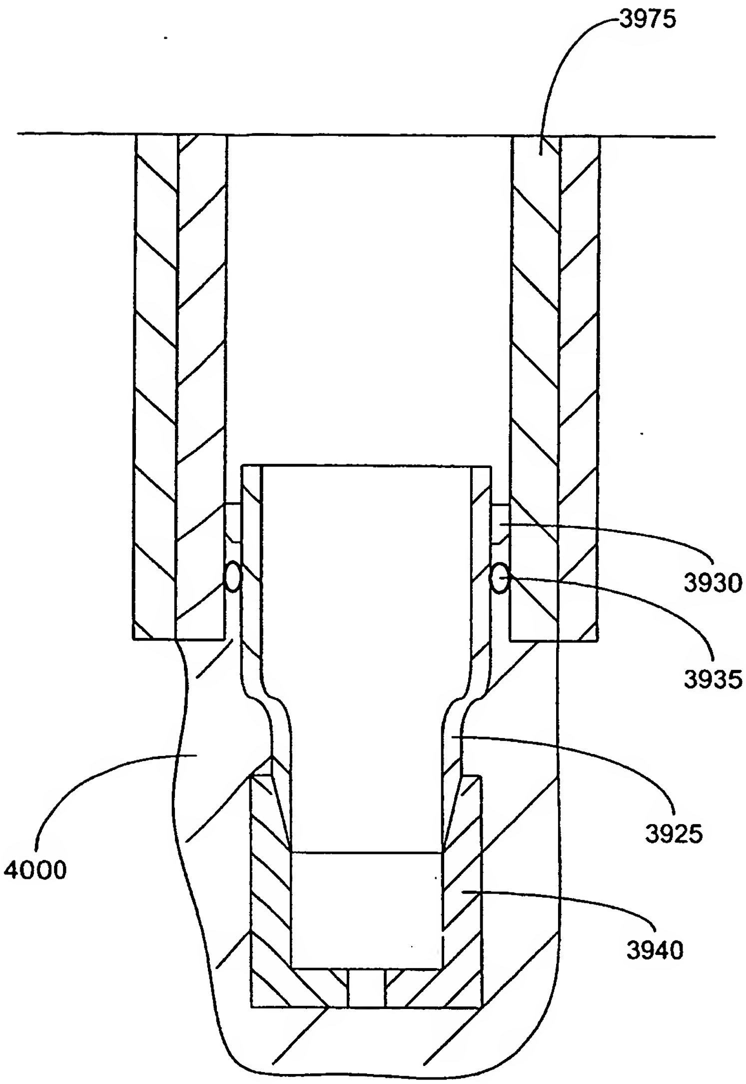


FIGURE 24E

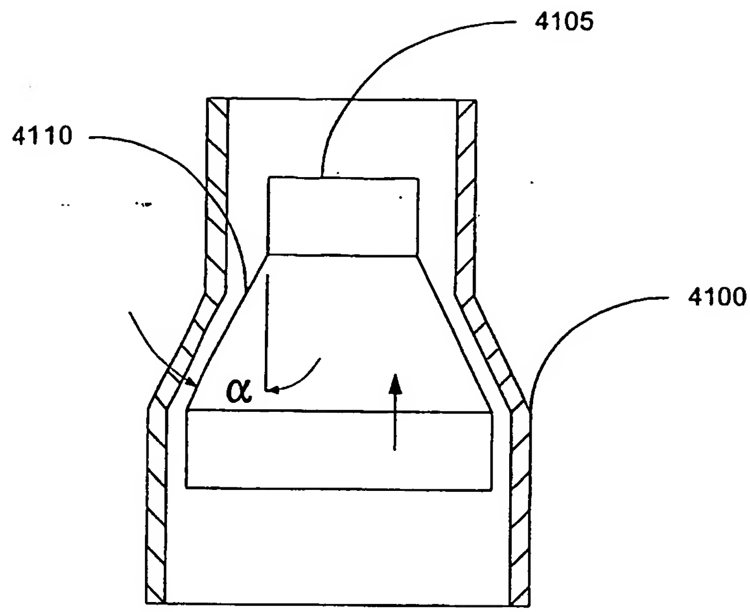


FIGURE 25

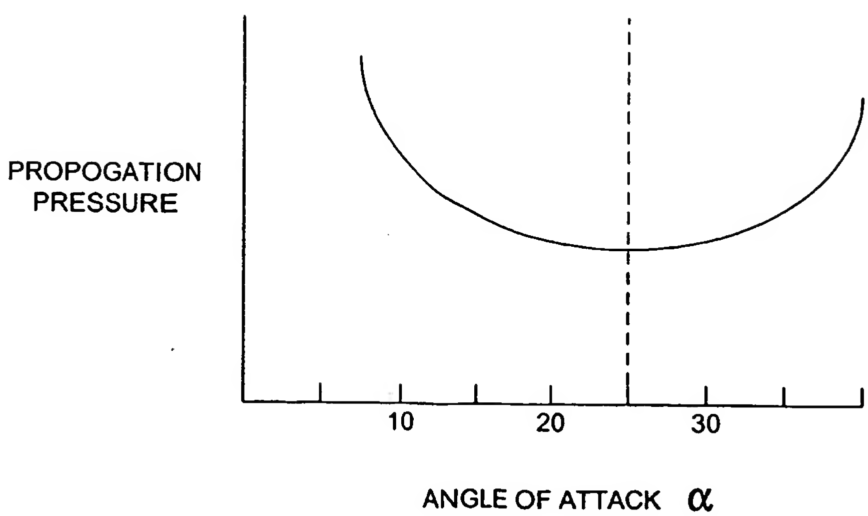


FIGURE 26

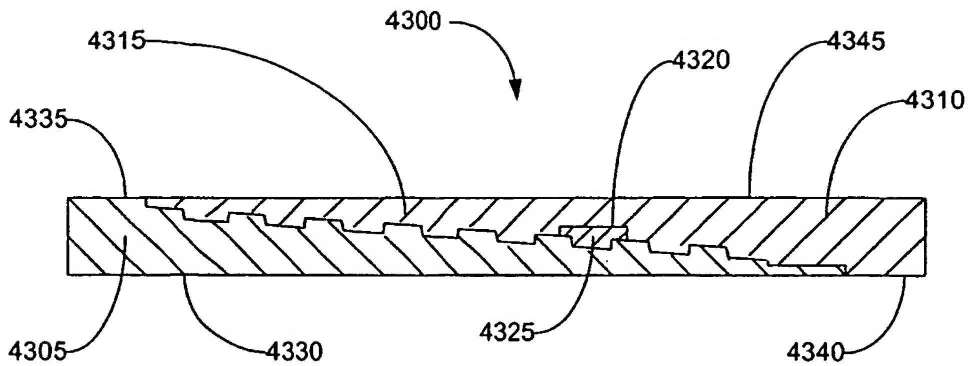


FIGURE 27

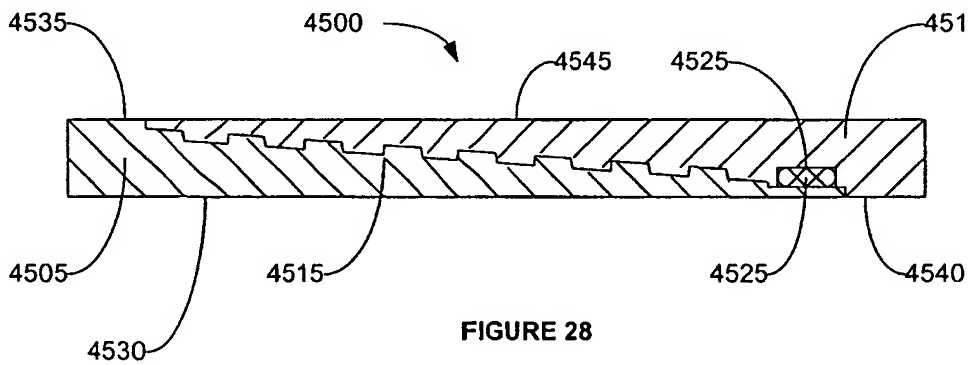


FIGURE 28

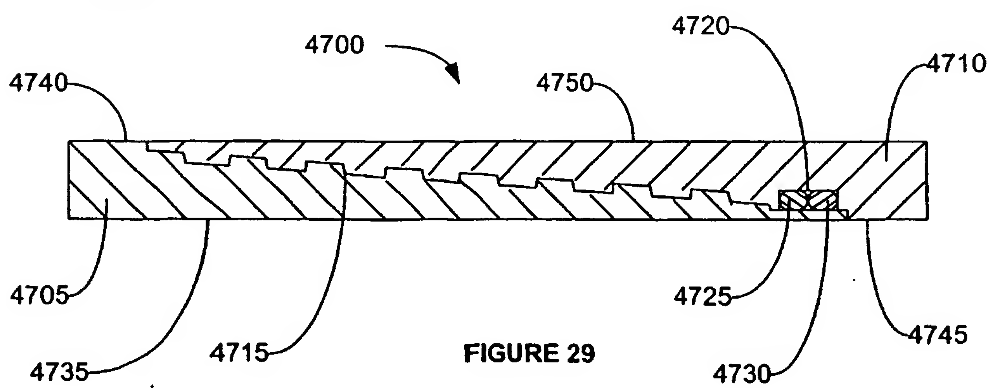


FIGURE 29

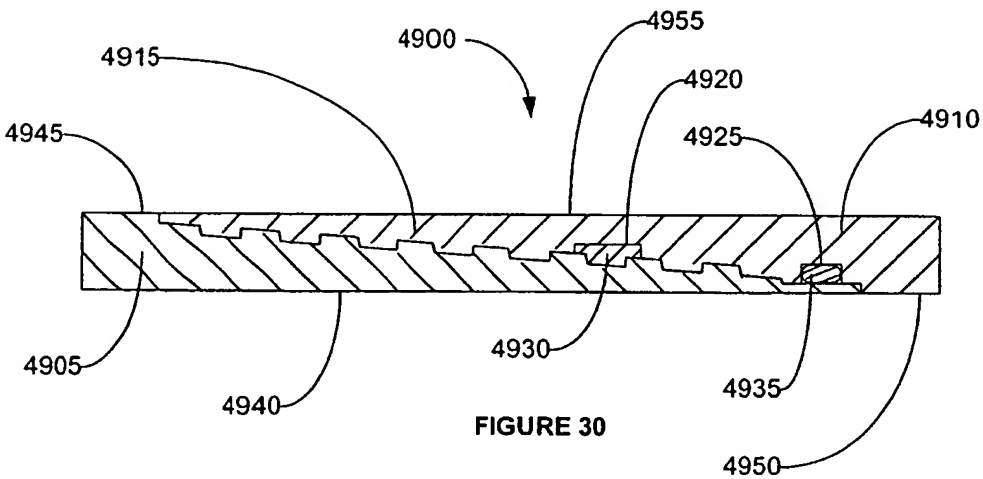


FIGURE 30

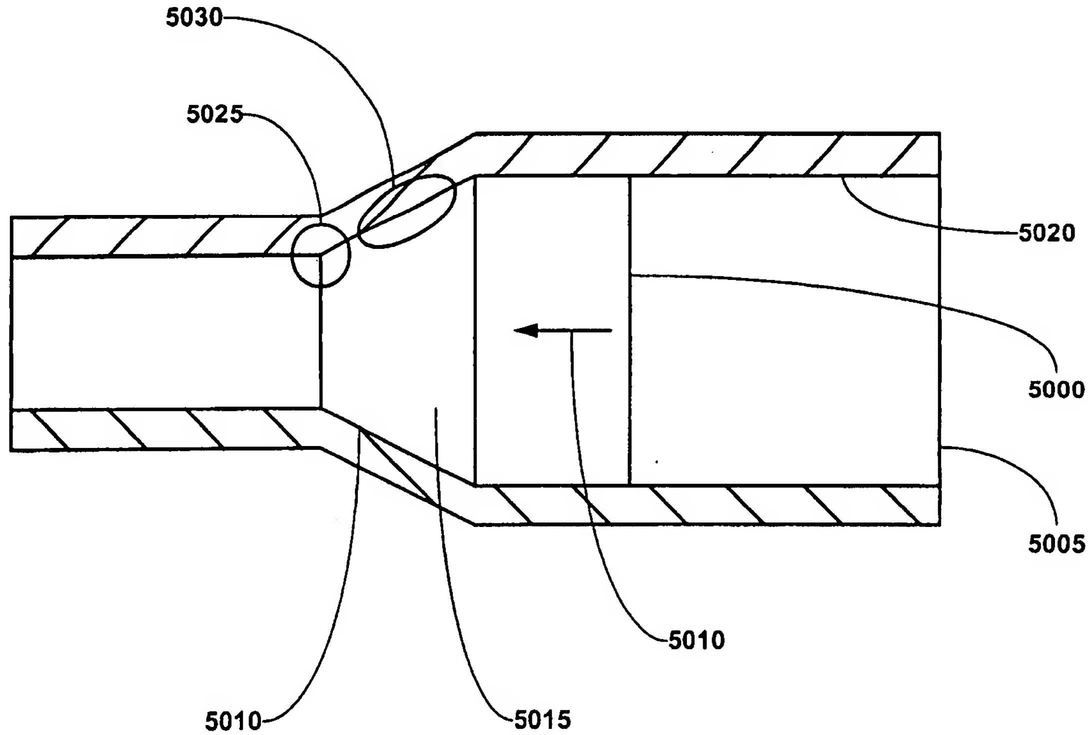


FIGURE 31

23 11 00 71777

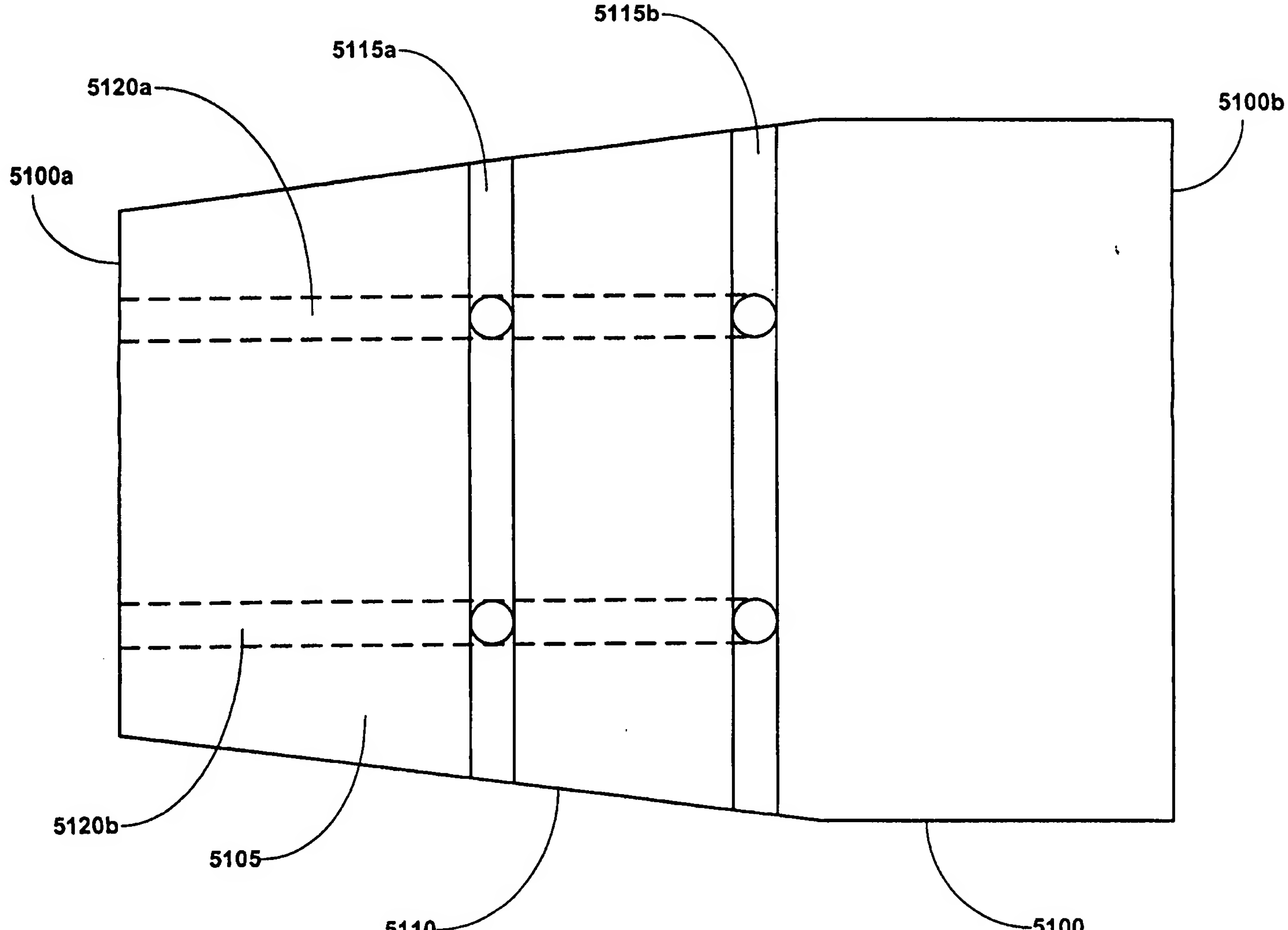


FIGURE 32

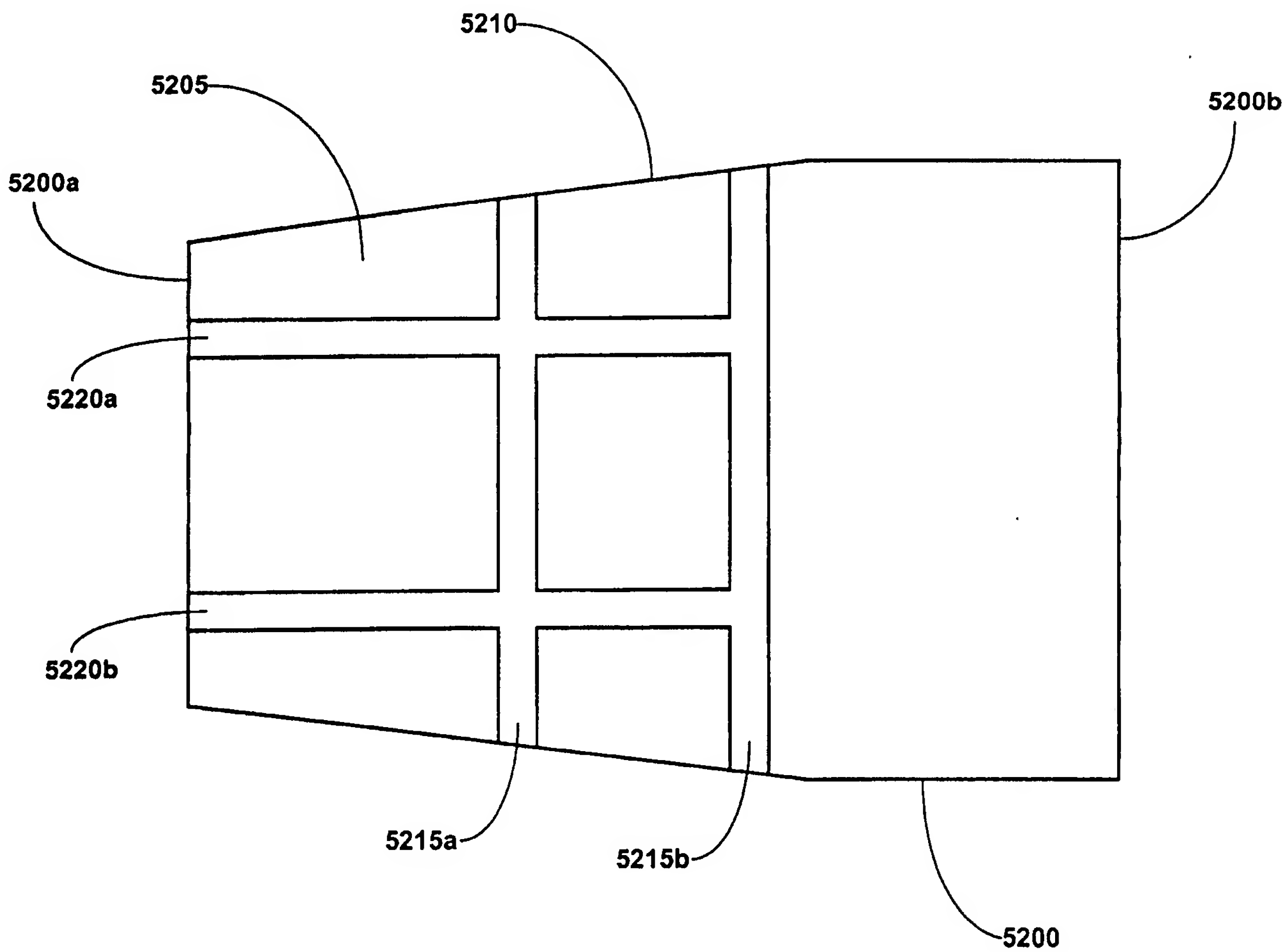


FIGURE 33

23 11 00 71777

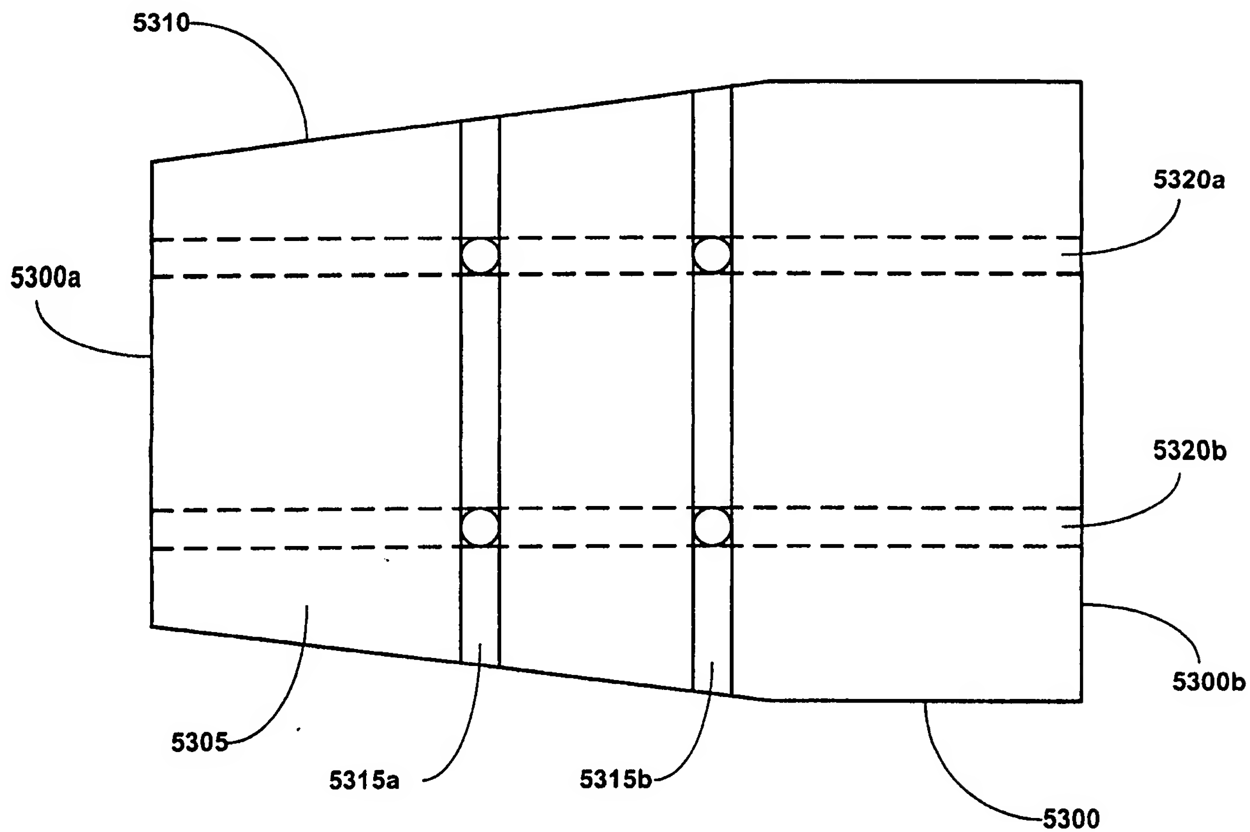


FIGURE 34

23 11 00 T1777

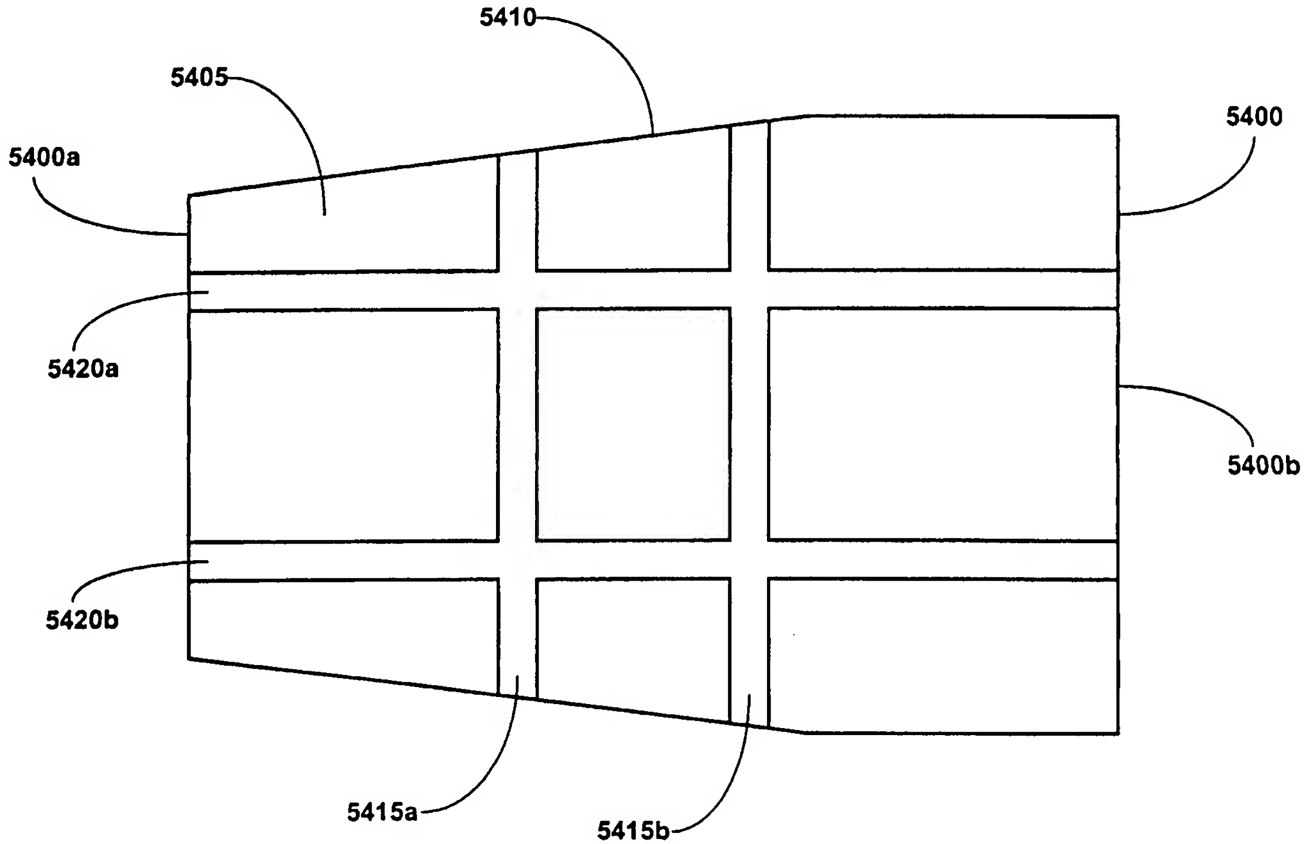


FIGURE 35

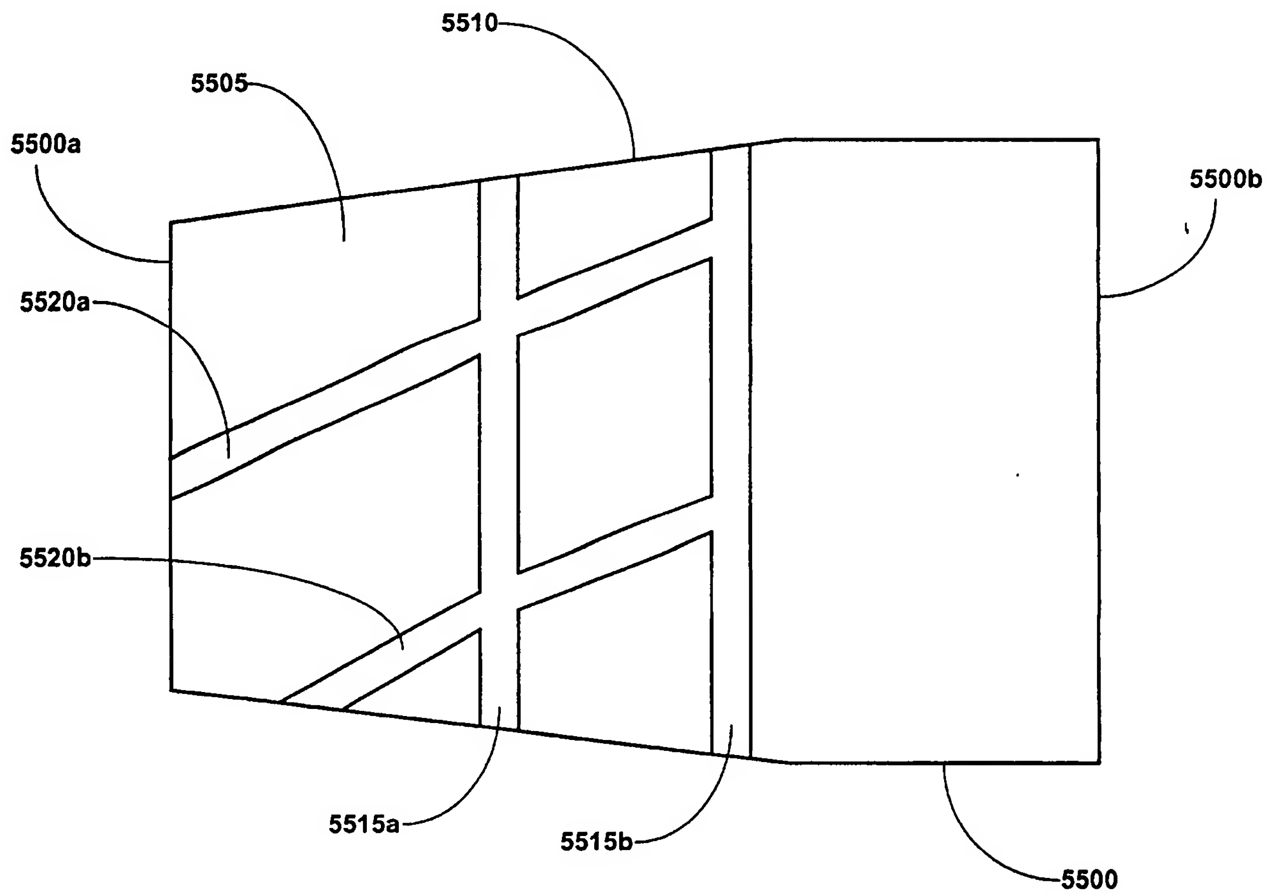


FIGURE 36

23 11 00 71777

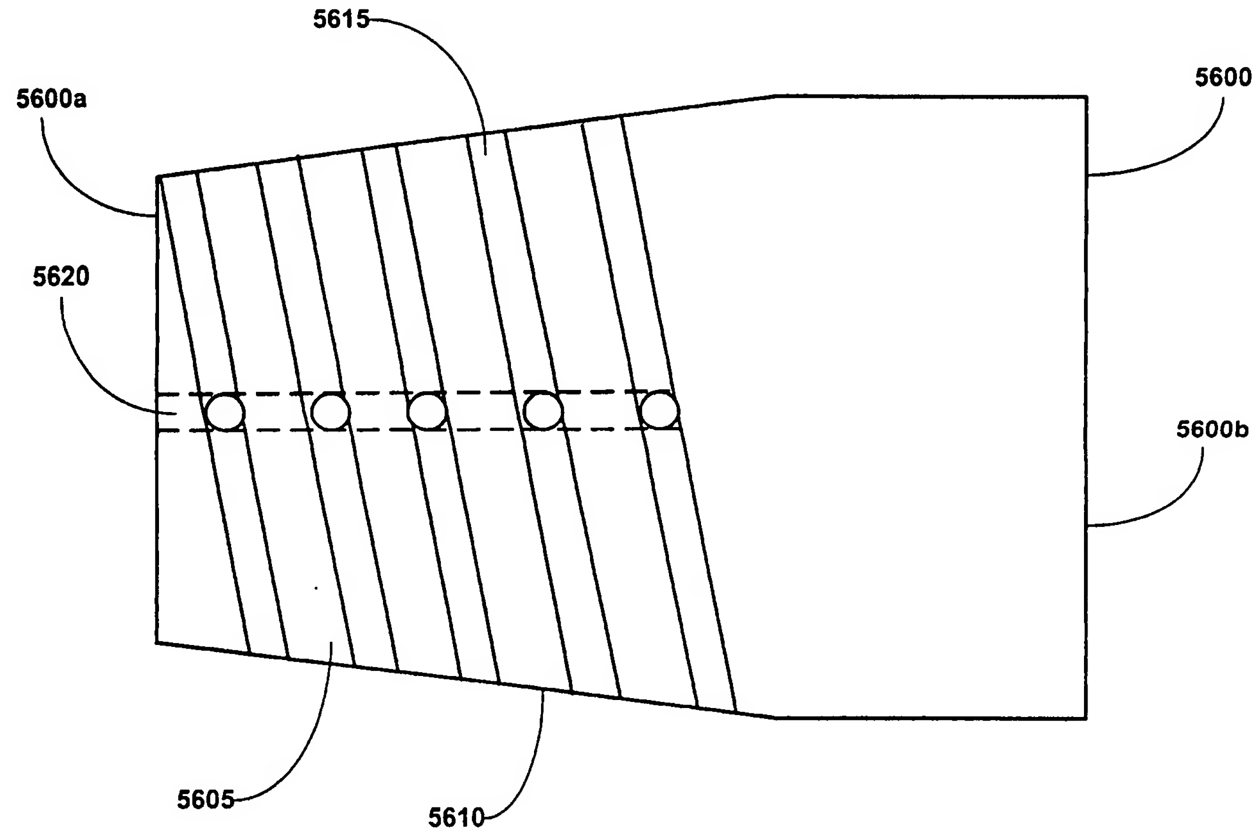


FIGURE 37

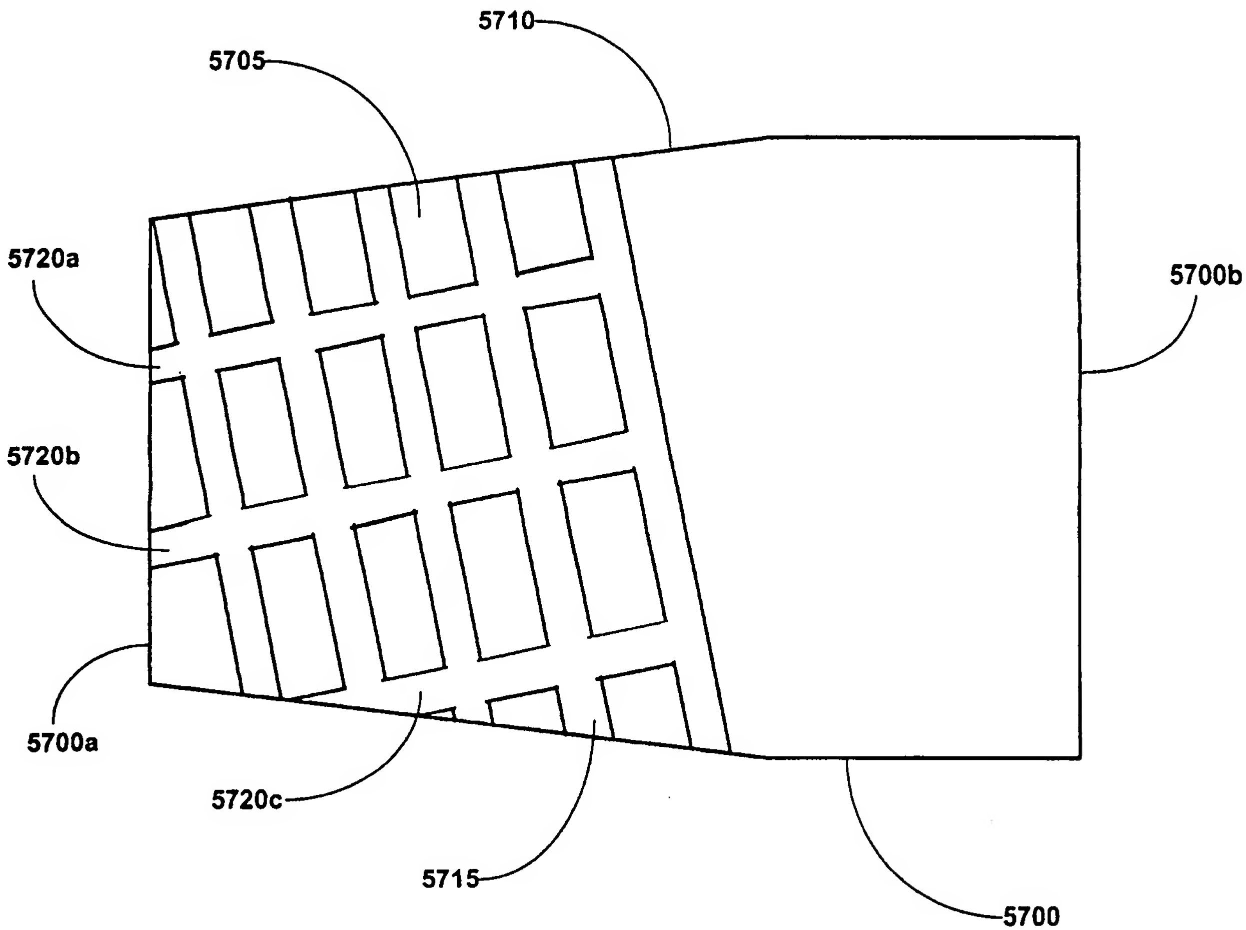
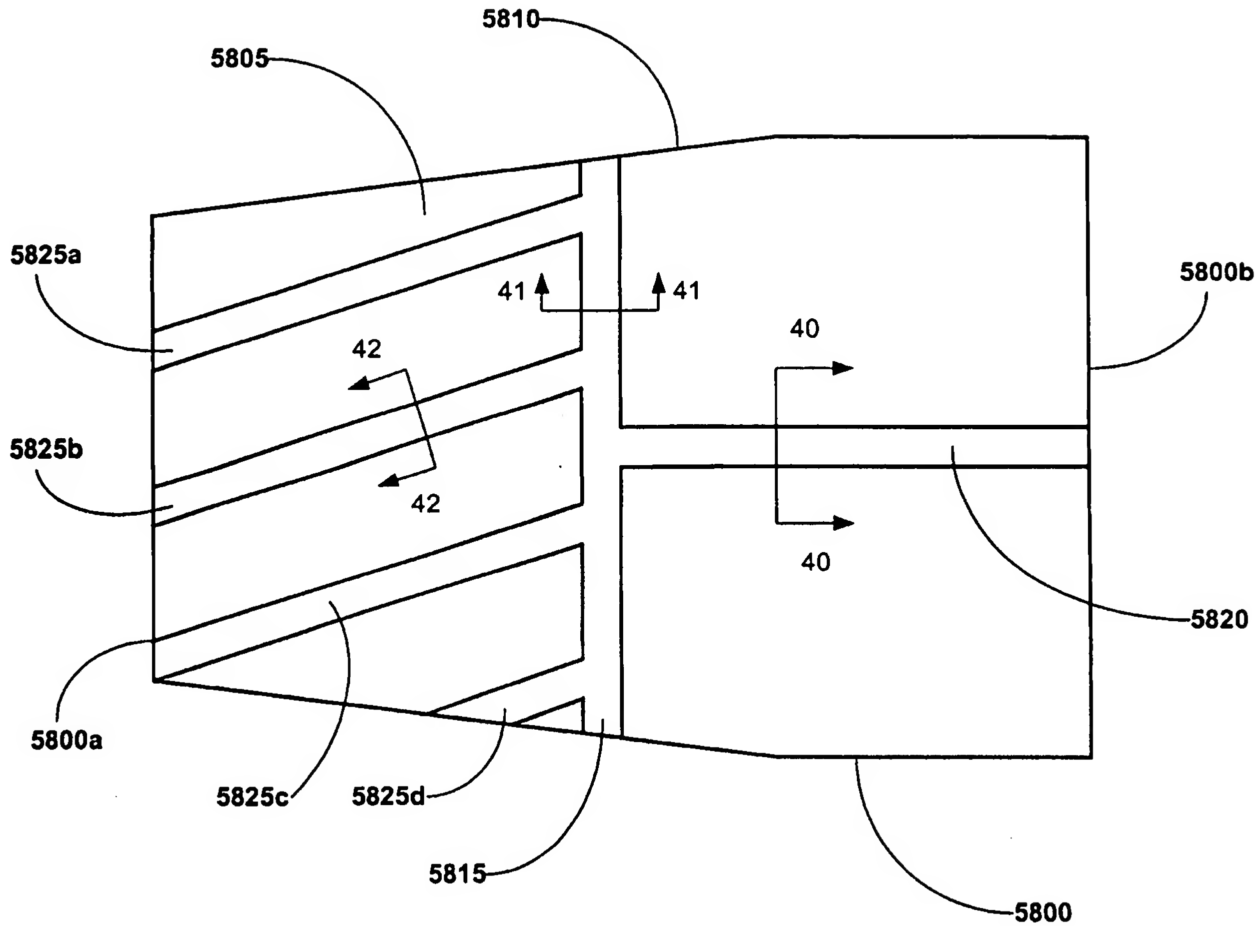


FIGURE 38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5825c
5825d
5815
5800

FIGURE 39

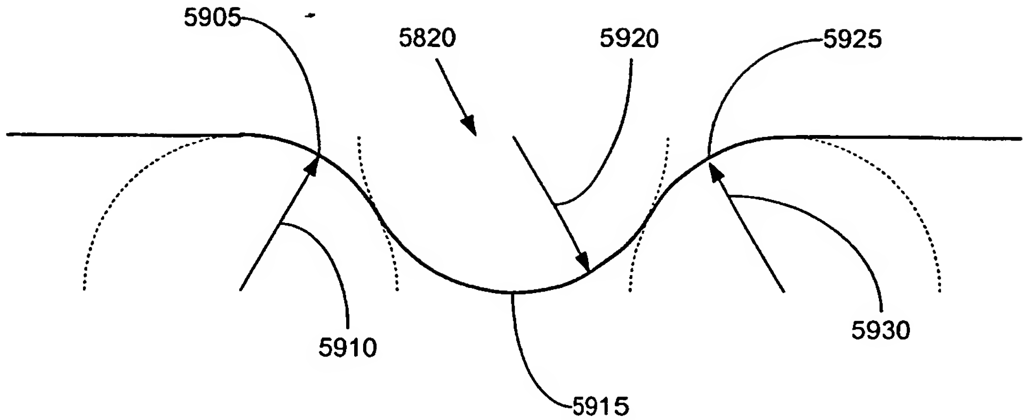

FIGURE 40

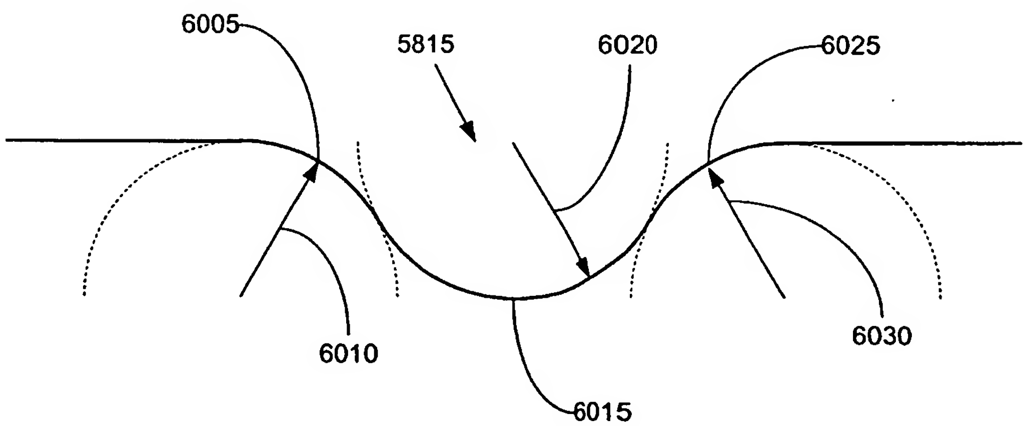

FIGURE 41

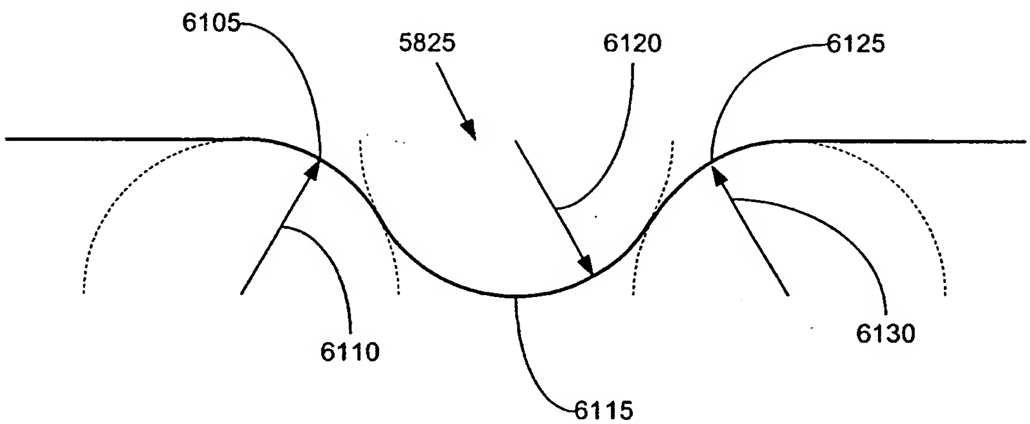

FIGURE 42

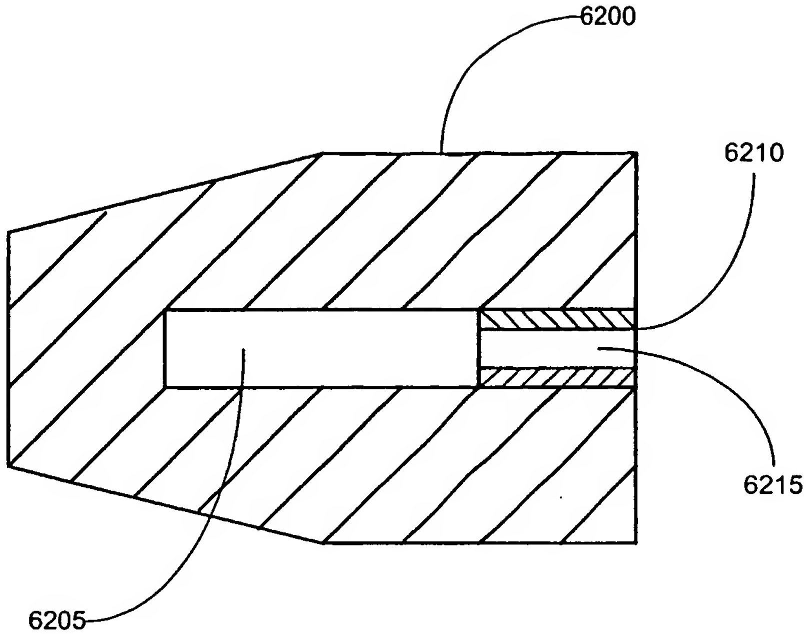

FIGURE 43

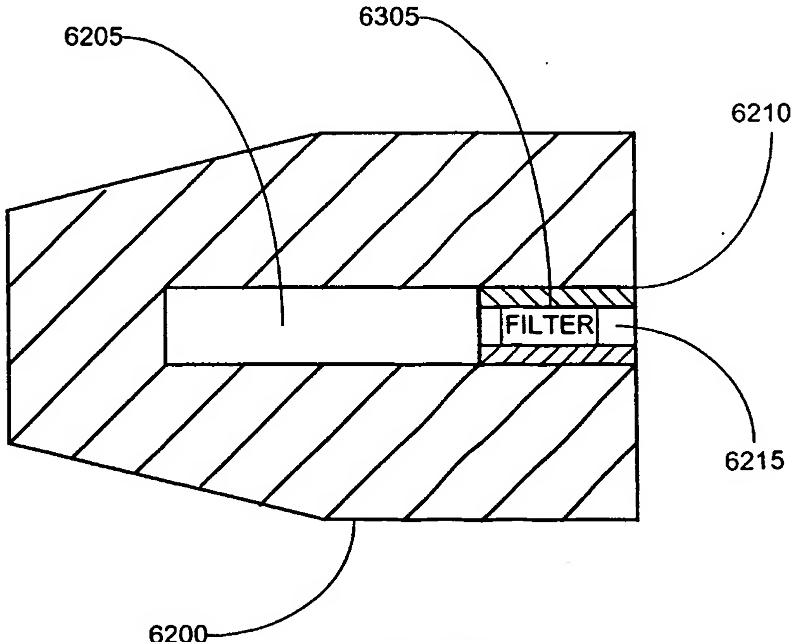

FIGURE 44

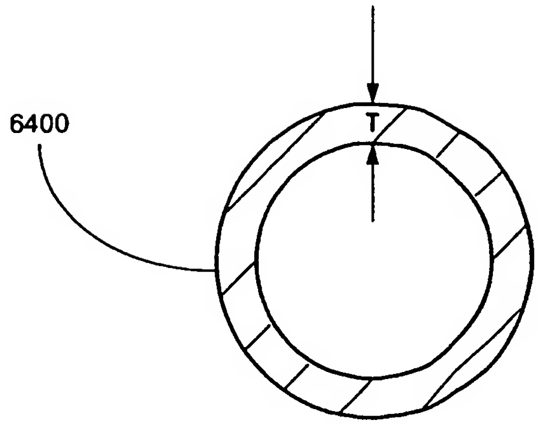

FIGURE 45

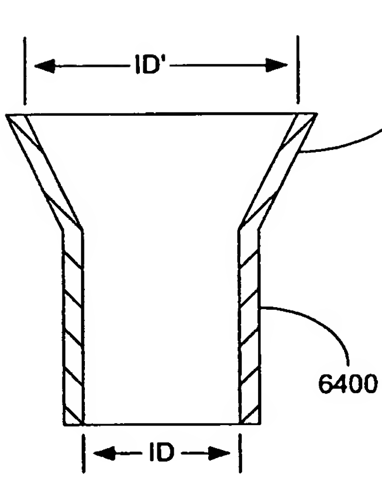

FIGURE 46

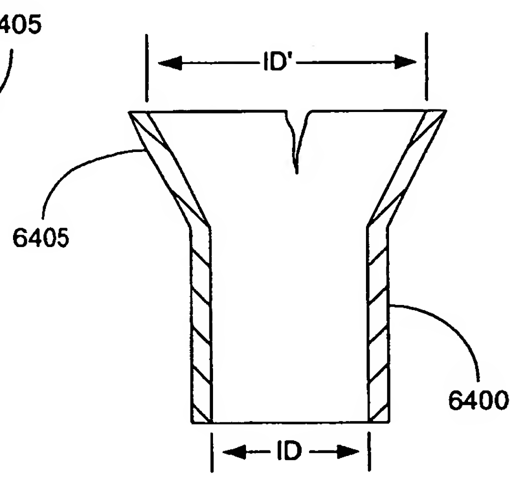

FIGURE 47